IN THE SUPERIOR COURT FOR THE STATE OF ALASKA

THIRD JUDICIAL DISTRICT AT ANCHORAGE

BP PIPELINES (ALASKA) INC.,
EXXONMOBIL PIPELINE COMPANY,
UNOCAL PIPELINE COMPANY,
CONOCOPHILLIPS TRANSPORTATION
ALASKA, INC. and KOCH ALASKA
PIPELINE COMPANY, Owners, and
ALYESKA PIPELINE SERVICE COMPANY,
as Agent for the Owners,

FAIRBANKS NORTH STAR BOROUGH and
CITY OF VALDEZ,

Appellants/Cross-Appellants,

v.

STATE OF ALASKA DEPARTMENT OF
REVENUE, STATE ASSESSMENT
REVIEW BOARD, and NORTH SLOPE
BOROUGH,

Appellees.

Case No. 3AN-06-08446 CI
(Consolidated)
2007/08/09 Tax Years

DECISION FOLLOWING TRIAL DE NOVO

**2007, 2008, and 2009 Assessed Valuations
of the Trans Alaska Pipeline System**

TABLE OF CONTENTS

I. PROCEDURAL BACKGROUND

1. This is a consolidated appeal of the State Assessment Review Board ("SARB" or "Board") Decisions of the 2007, 2008, and 2009 assessments of the Trans Alaska Pipeline System ("TAPS") for ad valorem tax purposes under AS 43.56. SARB assessed the value of TAPS for 2007 at $4.588895312 billion, for 2008 at $6.154447972 billion, and for 2009 at $9.045892 billion.[1]

2. SARB's 2006 assessment of TAPS was also appealed to this Court. After a de novo trial of over five weeks in 2009, this Court issued an Amended Decision Upon Reconsideration Following Trial De Novo on October 26, 2010, ("Amended Decision") with respect to that tax year, which concluded that the assessed value of TAPS for 2006 was $9.977 billion. That decision is currently on appeal to the Alaska Supreme Court.

3. The appeal to this Court of the 2007 through 2009 tax years culminated in a non-jury trial that began on September 6, 2011 and lasted approximately nine weeks.[2] Thousands of pages of exhibits and extensive deposition testimony were admitted into the record, together with the trial testimony of the parties' many witnesses. The administrative record for each of the SARB proceedings in 2007 through 2009 was also submitted to the Court.[3] And the parties have each filed extensive proposed Findings of Fact and Conclusions of Law that altogether total approximately 900 pages. Based on all the

[1] The three SARB decisions can be found in the trial exhibits at MUN7-0234 (2007), MUN7-0235 (2008) and MUN7-0236 (2009).

[2] *See* AS 43.56.130(i).

[3] Pursuant to the Court's Order Re Motion to File Expert Reports and Admit the SARB Record (July 26, 2011) at 6, the SARB record and hearing transcript for each of these years was admitted into the court record. *See also* Appellate Rule 609(b)(2).

evidence in the record, the arguments of counsel, the parties' proposed findings, and upon consideration of the applicable law, this Court is now entering the following Findings of Fact and Conclusions of Law.[4]

4. AS 43.56.010 *et seq.* are the statutes governing the ad valorem taxation of oil and gas property in Alaska. The statute provides for such property to be centrally assessed each year by the Tax Division ("Division") within the Department of Revenue ("Department"), based on a lien date of January 1. Taxpayers and affected local governments have the right to appeal the Division's assessed valuation to SARB, which is created within the Department. These parties then have a right to appeal from SARB to the Superior Court in the form of a trial de novo pursuant to AS 43.56.130. The TAPS Owners,[5] the Fairbanks North Star Borough, and the City of Valdez appealed SARB's 2007 decision to this Court. These parties, as well as the North Slope Borough, appealed SARB's 2008 and 2009 decisions to this Court. The three years were consolidated for purposes of trial. The Department and SARB are appellees in each of the three appeals.[6] The Municipalities have asserted to this Court that TAPS' assessed value should be $13.689 billion for 2007, $14.804 billion for 2008, and $14.422 billion for 2009.[7] The Owners have asserted that TAPS' assessed value should be $1.1 billion for 2007, $1.2 billion for 2008, and $1.3 billion

[4] This Court is cognizant of Civil Rule 52(a)'s specification that the Court "shall find the facts specifically and state separately its conclusions of law thereon." But for ease of comprehension of a decision with this number of issues and level of complexity, this Court has not segregated the conclusions of law, but instead notes that instances in which this Court is interpreting the law, as opposed to making factual findings, should be clear from the context of this decision. *See* Civil Rules 92, 94.

[5] The Owners of TAPS are BP Pipelines (Alaska) Inc., ConocoPhillips Transportation Alaska, Inc., ExxonMobil Pipeline Company, Koch Alaska Pipeline Company, and Unocal Pipeline Company (hereinafter "Owners").

[6] AS 43.56.040.

[7] Municipalities' Proposed Findings of Fact and Conclusions of Law ¶ 893.

for 2009.[8] The Department did not present an opinion of value for TAPS at the trial de novo for the three tax years at issue.[9]

5. AS 43.56.080 grants the Division certain investigative powers when assessing AS 43.56 properties, including the power to "enter any premise necessary for the investigation during reasonable hours," to "examine property and appropriate records," and to compel owner representatives "to appear for examination under oath by the department."[10] There was no persuasive evidence presented at the trial de novo that the Division has ever exercised these powers with respect to the valuation of TAPS.[11]

6. The Division broadly interprets what it considers "taxpayer confidential" information under applicable statutes and will not disclose such information to the Municipalities specifically or to the public generally.[12] The Division considers all information that it receives from a taxpayer as "taxpayer confidential," even if it does not contain the particularities of a taxpayer's business affairs and is obtainable from the public domain.[13] As a result, the Division did not provide the Owners' new replacement cost study by Stantec Consulting, Inc. ("Stantec") to the Municipalities.

---

[8] TO-07-0004.0138.

[9] The Department indicated that it did not render opinions of value at the trial de novo

> because in doing so it would be rendering a supplemental assessment for each of the years in question, which, in turn would trigger a new round of administrative action and appeals for each tax year rather than a single and definitive presentation in a de novo context before the court.

Department's Proposed Findings of Fact and Conclusions of Law ¶ 6.

[10] AS 43.56.080.

[11] *See* Greeley Dep. at 209 (June 6, 2011).

[12] *See* AS 40.25.100(a); AS 43.05.230(a).

[13] Tr. 10875-77 (Bales).

7. AS 43.56.060(g) provides that "[t]he department may enter into agreements with a municipality for the cooperative or joint administration of the assessing authority conferred on the department by this section."[14] The North Slope Borough previously had such an agreement with the Department. The City of Valdez and Fairbanks North Star Borough have never been parties to joint assessment agreements with the Department.[15]

8. In its 2010 decision, SARB expressed its concerns regarding the Division's assessment practices:

> The Board believes that it is time for the Division to address the problems created by the way it handles taxpayer confidential information in the assessment process. The Division's failure to provide interested parties with the information on which the assessment was made in time to allow those parties meaningful input in the determination of the property's assessed value, before that determination is subject to limited review of an appeal before the Board, has the potential to throw the fundamental fairness of the AS 43.56 assessment process into question. The Board believes that, due to the Division's current practices with regard to the use of taxpayer confidential information in its AS 43.56 assessments, that process is close to broken and is headed in the wrong direction.[16]

This Court concurs with the Board's observations in this regard.

9. The procedural inadequacies at the agency level have by and large been remedied on appeal to this Court due to the applicability of the civil discovery rules, albeit at considerable expense and delay.

10. This Court interprets the phrase "proved at the hearing" of subsection (f) of AS 43.56.130 to permit a party to introduce new evidence at the trial de novo. As a result, while

[14] AS 43.56.060(g).

[15] 2007 SARB Tr. 0137-0138 (Greeley).

[16] MUN7-0237 at 39.

the SARB hearings have each lasted a few days, the consolidated trial de novo before this Court for the 2007 through 2009 tax years' assessments lasted approximately nine weeks.

11. Nearly all the witnesses at the trial testified as experts or as hybrid fact and expert witnesses, and extensive expert reports were prepared. Their qualifications were set out in detail in their testimony and are not restated in this decision. In the 2006 tax year litigation, expert reports for all of the parties were admitted into evidence by stipulation of the parties. For the three tax years now at issue, the Owners maintained a hearsay objection to the admission of most of the expert reports, including most of the reports prepared by their own experts. In a July 26, 2011 "Order re Motion to File Expert Reports and Admit the SARB Record," this Court stated that Evidence Rule 803(23) could be an applicable exception to the hearsay rule for these reports in this proceeding. Over the objection of the Municipalities and the Department, the Owners were permitted to maintain their objection to the admission of most of the expert reports under Rule 803(23), including their own experts reports, while nonetheless seeking admission of their own reports.[17] During and after trial, most of the expert reports were admitted into the record.[18] However, given the extensive dispute between the parties with respect to most of the expert reports, this Court has minimized its consideration of those reports. Any expert report that was admitted over objection of any party has not been relied upon or considered by this Court in determining

[17] *See* Order re Expert Reports (Oct. 24, 2011).

[18] *See* Order Re Owners' Motion to Admit Exhibits (Nov. 29, 2011).

the assessed value of TAPS for the three years in question, excepting only those specific pages of reports identified in this decision.[19]

12. The proceedings surrounding these three tax years have been considerably more contentious than those held with respect to the 2006 tax year. Several hundred pretrial motions were filed and determined. This Court issued an Order Re Department of Revenue's Motion for Preclusion of Issues and Municipalities' Motion to Bar Relitigation on August 8, 2011 ("Collateral Estoppel Order"). That Order would have applied the doctrine of collateral estoppel so as to preclude the relitigation of many of the determinations reached by this Court in the 2006 tax year proceeding to the current tax years, while preserving each party's right to seek to introduce newly discovered evidence "that purports to demonstrate changed facts such that application of collateral estoppel would not be warranted."[20] However, for reasons that this Court strived to fully explain on record at trial on September 13 and 19, 2011, that Order was vacated and the trial de novo then proceeded with respect to all pending issues.[21]

13. The length of the trial proceeding was not primarily due to the fact that three years were heard at one time. Indeed, very little trial time was spent focusing on the differences between the three lien years. Rather, the evidence focused on each of the substantive issues applicable to all three tax years. Each of the parties presented a considerably more technical and in-depth analysis of many of the issues identified in the 2006 tax year proceeding.

[19] There have been multiple occasions in recent months that this Court has reviewed expert reports for other purposes, such as to determine whether a motion to preclude testimony should be granted, or whether certain trial testimony fell within the scope of opinions discussed in the report. *See* Evidence Rule 104.

[20] Collateral Estoppel Order at 4.

[21] Tr. 2906-08 (Court).

14. Pursuant to this Court's August 25, 2011 Order Re Remaining Pretrial Issues and Amended Order Of Presentation, this Court heard testimony and evidence from each of the parties by topic area presented in the following order:

a. Appraisal Theory
b. Replacement Cost New (including contingency)
c. Economic/Regulatory/Contractual Issues
d. Mechanical Capacity – both upper and lower
e. Reserves/North Slope Production Forecasts
f. Appraisal/Valuation of TAPS

II. LEGAL STANDARDS

A. Taxation Authority

15. "The Alaska Constitution empowers the legislature to prescribe valuation standards."[22] "The legislature chose to define those standards broadly, requiring that property be assessed 'at its full and true value.'"[23]

16. AS 43.56.010 *et seq.* became law in 1973. These statutes provide that property used for oil and gas exploration, production, and pipeline transportation would not be valued for assessment purposes by municipalities under AS 29.45; instead these types of properties would each be uniformly and centrally assessed by the State.[24]

17. AS 29.45.080(b) provides that "[a] municipality may levy and collect a tax on the full and true value of taxable property taxable under AS 43.56 as valued by the Department of Revenue . . . ."

[22] *Fairbanks N. Star Borough Assessor's Office v. Golden Heart Utils., Inc.*, 13 P.3d 263, 267-68 (Alaska 2000). *See also* Alaska Const., art. IX, § 3.

[23] *Golden Heart Utils.*, 13 P.3d at 267-68.

[24] *Minutes* at 50, 54, H. Fin. Comm., 8th Leg., 1st Spec. Sess. (Oct. 22, 1973); *Minutes* at 76, H. Fin. Comm., 8th Leg., 1st Spec. Sess. (Oct. 24, 1973); S.J. at 81-82, 8th Leg., 1st Spec. Sess. (Nov. 3, 1973); Amended Decision ¶ 15.

18. AS 43.56.060(e)(2) provides in relevant part:

> The full and true value of taxable property used or committed by contract or other agreement for pipeline transportation of gas or unrefined oil or in the operation or maintenance of facilities for the pipeline transportation of gas or unrefined oil is: . . .
>
> (2) determined on each January 1 thereafter with due regard to the economic value of the property based on the estimated life of the proven reserves of gas or unrefined oil then technically, economically, and legally deliverable into the transportation facility[.]

19. The Department of Revenue's implementing regulation for the statute provides:

> [T]he full and true value of pipeline property in operation is its economic value based upon the estimated life of proven reserves of the gas or oil then technically, economically and legally deliverable into the transportation facility. Economic value is determined by the use of standard appraisal methods such as replacement cost less depreciation, capitalization of estimated future net income, analysis of sales, or other acceptable methods. The valuation may include any item contributing to value including capitalized interest.[25]

This regulation has been in place since 1975 and in this precise form since 1982.

20. The implementing regulation differs slightly from the statute, as the regulation provides that "the full and true value of pipeline property in operation *is* its economic value based on the estimated life of proven reserves ..." (Emphasis added). If a statute and a regulation conflict, the provisions of the statute control.[26]

21. Each year, as part of the ad valorem assessment process, the property owners file a rendition with the Department identifying all taxable property.[27] There has been no

[25] 15 AAC 56.110(c)

[26] *State v. Kenaitze Indian Tribe*, 83 P.3d 1060, 1064-1065 (Alaska 2004).

[27] The renditions filed by the TAPS Owners for each of the applicable years can be found in the SARB record as follows: 2007 R. 001076 – 1087; 2008 R. 003989 – 4036; 2009 R. 003528 – 3618.

claim or appeal point raised that the property identified in the TAPS Owners' renditions is not taxable under AS 43.56.060(e)(2). Nor does this Court find that there is any escaped property.[28] Accordingly, this Court finds that all property included in the 2007, 2008, and 2009 Owners' renditions is taxable under AS 43.56.060(e)(2).

B. Standard of Review and Burden of Proof

22. This Court has previously determined in the 2006 tax year proceeding, and again holds, that the appellants bear the burden of proof to demonstrate by a preponderance of the evidence that an adjustment from SARB's assessed value is warranted pursuant to the standard in AS 43.56.130(f): "The only grounds for adjustment of assessed value is proof of unequal, excessive, or improper valuation or valuation not determined in accordance with the standards set out in this chapter."[29]

23. This Court will accord deference to SARB's interpretation of the statutory premise of value established by the Legislature in AS 43.56.060(e)(2) because the legal interpretation of that statute "implicates agency expertise or the determination of fundamental policies within the scope of the agency's statutory functions."[30] The Board, in

---

[28] Tr. 13063 (Greeley).

[29] *See* Amended Decision ¶ 20. In addition, a party could present a constitutional challenge to an administrative determination. *Id.* ¶ 20 n.9.

[30] *See Bullock v. State, Dept. of Comm. Affairs,* 19 P.3d 1209, 1213-14 (Alaska 2001) (applying "highly deferential" reasonable basis standard of review to the Department of Revenue's statutory interpretation regarding AS 43.56 property). *See also Storrs v. State Med. Bd.*, 664 P.2d 547, 552 (Alaska 1983) *cert. denied*, 464 U.S. 937 ("Statutory construction adopted by those responsible for administering a statute should not be overruled in the absence of 'weighty reasons.'"). In contrast, if the interpretation of a statute does not involve agency expertise, such that the "agency's specialized knowledge and experience would not be particularly probative as to the meaning of the statute," then this Court is to interpret the statute under the substitution of judgment standard, and "adopt the rule of law that is most persuasive in light of precedent, reason, and policy." *Williams v. Abood*, 53 P.3d 134, 139 (Alaska 2002). *See also* Sutherland § 66.4 at 48 (3rd ed. 2003) ("One of the most significant aids of construction in determining the meaning of revenue laws is the administrative interpretation given such acts by the agency that is responsible for its administration and enforcement.").

turn, has accorded deference to the Division in this regard. And yet this Court is cognizant that the volunteer Board had only a few days of testimony each year to consider the value of TAPS, whereas this Court had nine weeks of trial together with extensive pretrial motion practice. But having studied each of SARB's decisions for the three applicable tax years and the preceding years, this Court has found the Board's analysis, and particularly its discussion of appraisal theory, to be quite helpful in determining the assessed value of TAPS.

24. The Alaska Supreme Court has accorded broad discretion to taxing authorities in determining the valuation method.[31] The appellants must prove that the selected method was based on a fundamentally wrong principle of valuation.[32]

25. As to the application of appraisal methodology and all other issues that were not before the Board, this Court has engaged in original fact finding, and applied a preponderance of the evidence standard to determine whether SARB's assessed values resulted in unequal, excessive, or improper valuations.

26. In evaluating the evidence, the Court has considered Civil Pattern Jury Instruction 02.23:

> The evidence should be evaluated not only by its own intrinsic weight but also according to the evidence which is in the power of one party to produce and of the other party to contradict. If weaker and less satisfactory evidence is offered when it appears that stronger and

[31] *See Marathon Oil Co. v. Dep't of Natural Res.*, 254 P.3d 1078, 1082 (Alaska 2011); *Horan v. Kenai Peninsula Borough Bd. of Equalization*, 247 P.3d 990, 998 (Alaska 2011); *Fairbanks N. Star Borough Assessor's Office v. Golden Heart Utils.*, 13 P.3d 263, 268 (Alaska 2000); *Cool Homes, Inc. v. Fairbanks N. Star Borough*, 860 P.2d 1248, 19262 (Alaska 1993); *N. Star Alaska Hous. Corp. v. Fairbanks Borough Bd. of Equalization*, 778 P.2d 1140, 1143-44 (Alaska 1989); *Twentieth Century Inv. v. City of Juneau*, 359 P.2d 783, 788 (Alaska 1961).

[32] *See N. Star Hous. Corp.*, 778 P.2d at 1144 n. 6.

more satisfactory evidence was within the power of one party to produce, the evidence should be viewed with caution.

C. History of Ad Valorem Tax Assessments of TAPS

27. SARB is a five-member board created within the Department. Its sole purpose is hearing appeals from assessed value determinations made by the Division under AS 43.56.[33] Each member of SARB is appointed by the Governor, confirmed by the Legislature, and must be knowledgeable of assessment procedures.[34] In its 2007 TAPS determination, SARB stated it "is designed to provide a balanced expert review of oil and gas production property valuation issues."[35]

28. Prior to 2001, there were no administrative or court proceedings addressing the value of TAPS. Instead, the Division prepared a valuation based on consideration of both the income and cost approaches, with the income approach the more dominant in the analysis. Then the Division would meet with the Owners, typically in an out-of-state hotel conference room, and TAPS' assessed valuation would be determined in a negotiated settlement reached between the Division and the TAPS Owners with little, if any, participation by the Municipalities.[36]

29. In 2001, the Division valued TAPS at $2.75 billion. Both the Owners and the Municipalities appealed that determination to SARB. There, each party "relied most heavily

[33] AS 43.56.040.

[34] AS 43.56.040.

[35] MUN7-0234 at 21.

[36] MUN7-0234 at 4; Tr. 12419-12420 (Hoffbeck).

on projected TAPS tariff income data in setting their valuation estimates."[37] SARB stated in its 2009 Certificate of Determination:

> Because there had never been a replacement cost study for the TAPS, the 2001 cost value estimates had to be calculated based on the original cost of the TAPS. Having to adjust these original costs forward so many years made the valuations based on the original costs a very poor indicator of the 2001 value of the TAPS.[38]

30. In 2001, SARB concluded, based upon the evidence then available, that the Division's assessed value of $2.75 billion should be increased to $3.017 billion.[39]

31. From 2002 through 2004, the assessed valuation of TAPS remained at $3.017 billion as the result of negotiated agreements between the Division, the Owners and the Municipalities.[40]

32. In 2005, the Division set a $3 billion assessed valuation for TAPS.[41] In so doing, the Division relied primarily on the Replacement Cost New Less Depreciation ("RCNLD") approach because it had received updated replacement cost study information from both the Owners and the Municipalities.[42] In addition, "uncertainty about future tariff rates in 2005 led the Division to question whether the income approach using a capitalized estimated future tariff income stream still provided the most complete and reliable estimate of the value of TAPS."[43]

---

[37] MUN7-0234 at 4.

[38] MUN7-0236 at 6.

[39] MUN7-0236 at 7.

[40] MUN7-0236 at 7.

[41] MUN7-0234 at 8.

[42] MUN7-0234 at 8.

[43] MUN7-0234 at 8.

33. Both the Owners and the Municipalities appealed the Assessor's 2005 determination to SARB.[44] After a three-day hearing, the Board agreed with the Division that the value of TAPS could not be accurately measured by the tariff income approach because the uncertainty of future tariff rates and other factors caused the value of future tariff income streams to understate the full and true value of TAPS.[45] SARB also concluded that neither the Owners nor the Municipalities had proven that the Division's $3 billion assessed value was "unequal, excessive, improper or otherwise contrary to the standards set out in AS 43.56," even though the Board found that it was "at the low end of an acceptable value range."[46]

34. Both the Owners and the Municipalities appealed the 2005 SARB Decision to the Superior Court. However, by stipulation of the parties, the appeals were dismissed.

35. In 2006, the Division relied on the same basic data and RCNLD methodology as it had in 2005, and determined that the assessed value of TAPS was $3.641 billion.[47]

36. The parties appealed the Division's 2006 assessment to SARB.[48]

37. SARB adjusted the 2006 assessed value from $3.641 billion to $4.3062718 billion.[49] The Owners, as well as the Fairbanks North Star Borough and City of Valdez, appealed to this Court. A five week trial de novo was held in the fall of 2009. Thereafter, this Court issued a 170-page decision in 2010 that relied on the cost approach to valuation

---

[44] MUN7-0232 at 8.

[45] MUN7-0234 at 9.

[46] MUN7-0234 at 9.

[47] MUN7-0234 at 9.

[48] MUN7-0234 at 10.

[49] MUN7-0234 at 10.

and set the assessed value of TAPS for 2006 at $9.977 billion.[50] That Decision is presently on appeal to the Alaska Supreme Court.[51]

38. In 2007, the Division determined TAPS' assessed value was $4.578 billion.[52] Both the Owners and the Municipalities appealed to SARB. After a hearing, SARB concluded that the 2007 assessed value of TAPS was $4.588895312 billion.[53]

39. In its 2007 Decision, SARB held that the term "economic value" in AS 43.56.060(e)(2) "means more than the value obtained using a simple willing buyer, willing seller, open market model."[54] SARB reasoned:

> Often there is no open market for oil and gas transportation pipelines in production as stand alone properties. Often there is no willing buyer or a willing seller for an Alaska pipeline at [a] price that would reflect the pipeline's value. Attempts to create a model based on a willing buyer and willing seller may overstate or understate the value of such a pipeline because its value is often more closely tied to the economic life of [the] oil field it serves than its value in a theoretical open market without reference to the oil fields it serves. Hence Alaska Statute 43.56.060(e)(2) requires an assessed valuation based on the pipeline's economic value with due consideration given to the reserves the pipeline serves in estimating that economic value.[55]

40. In its 2007 Decision, SARB critiqued "the Division's frequent use of the term conservative in reference to some of its assumptions and estimates."[56] The Board added that "the object of an assessor valuing property under Alaska Statute 43.56.060(e)(2), is to make the best estimate of value, that is, to determine the pipeline's most likely value based

[50] Amended Decision ¶ 511.

[51] S-14095; S-14116.

[52] MUN7-0234 at 2.

[53] MUN7-0234 at 24.

[54] MUN7-0234 at 14.

[55] MUN7-0234 at 14. *See also* Amended Decision ¶ 53.

[56] MUN7-0234 at 20. *See also* Amended Decision ¶ 53.

on the available evidence, not to make a conservative estimate of value, or the lowest estimate of value within an acceptable range of possible values."[57]

41. In 2008, the Division determined that the assessed value of TAPS was $7.16589746 billion.[58] The parties appealed to SARB. There, the Owners asserted that TAPS' assessed value should be $800 million; the Municipalities argued that TAPS' assessed value should be set no lower than $12 billion.[59] SARB agreed with the Division that "the Pro Plus cost study [advanced by the Municipalities] was generally more detailed and more reliable than the current and previous Mustang cost study."[60] However, SARB did not accept the Pro Plus contingency estimate of 25%.[61] The Board concluded that the increased reliability of the Pro Plus study should have resulted in the contingency going down, not up, and it therefore set the contingency at 5%.[62]

42. After adjusting the contingency percentage, SARB concluded that the assessed value of TAPS in 2008 was $6.15447972 billion.[63] SARB commented that an assessed value may increase from year to year due to the availability of more reliable data, "even if the actual value of the property did not change."[64]

43. By 2009, the Municipalities and the Department had received significant materials through the discovery process in the 2006 case before this Court.

---

[57] MUN7-0234 at 20. *See also* Amended Decision ¶ 55.

[58] MUN7-0235 at 26.

[59] MUN7-0235 at 2.

[60] MUN7-0234 at 19.

[61] MUN7-0235 at 19-20.

[62] MUN7-0235 at 19-20.

[63] MUN7-0235 at 26.

[64] MUN7-0235 at 25.

44. In 2009, the Division accepted and relied upon the Municipalities' Pro Plus study but reduced the contingency from 25% to 10% and the owners' costs from 10% to 5%, and valued the property at $7.71506816 billion.[65] Both the Owners and the Municipalities appealed to SARB.

45. Before SARB in 2009, the Owners asserted that TAPS' value was less than $1 billion; the Municipalities argued that TAPS' assessed valuation should be set no lower than $12 billion.[66] SARB found that the Pro Plus witnesses had provided full support for a 25% contingency and owners' costs of 10%.[67] Accordingly, SARB adjusted the Division's value for these two items to result in an assessed valuation of $9.0458952 billion.[68]

46. In each of the 2007 through 2009 assessments of TAPS, both the Division and SARB concluded that:

a. after due consideration of the income and sales approaches, the cost approach was most applicable to value TAPS;

b. TAPS was a special use or special purpose property; and

c. the assessed value was based on the best cost studies then available to the Division and SARB, which in 2007 was comprised of a trended version of an older Mustang cost report, in 2008 was comprised of a Pro Plus pipeline replacement cost based on a cost-estimated "Spread 6" and factored for Spreads 1-5, combined with a Mustang Valdez marine terminal ("VMT")

---

[65] MUN7-0236 at 2.

[66] MUN7-0236 at 2.

[67] MUN7-0236 at 17, 19.

[68] MUN7-0236 at 18.

replacement cost estimate, and in 2009 was comprised of a full Pro Plus pipeline and VMT cost estimate.[69]

47. In 2010, the Division valued TAPS at $9.20346143 billion.[70] The Owners presented a new cost study prepared by Stantec.[71] At the ensuing 2010 SARB hearing, the Owners asserted that TAPS was worth no more than $1.4 billion. The Municipalities asserted that TAPS' assessed valuation should be set at $11.8 billion.[72] The Board adjusted the Assessor's calculation of ad valorem taxes during construction and the economic end-of-life for TAPS, with a resultant valuation of $9,638,669,398.[73] That determination is presently on appeal to this Court, but a trial date has not yet been scheduled.

48. In 2011, the Division valued TAPS at $7.9329798 billion.[74] The Owners and Municipalities appealed that valuation to SARB. The Board found that the Division's valuation was improper because it failed to give this Court's decision in the 2006 TAPS appeal proper weight in making an economic end-of-life calculation.[75] After making this adjustment to the Division's valuation, the Board determined that the 2011 assessed valuation of TAPS was $8,671,720,679.[76] That determination is also on appeal to this Court.

---

[69] Tr. 6758-52 (Greeley).

[70] MUN7-0237 at 1.

[71] MUN7-0237 at 19.

[72] MUN7-0237 at 2.

[73] MUN7-0237 at 42.

[74] MUN7-0238 at 2.

[75] MUN7-0238 at 19.

[76] MUN7-0238 at 34.

49. The Board's Certificates of Determination for 2010 and 2011 reflect careful consideration of this Court's rulings from the 2006 tax year to the years at issue before the Board, thereby according some degree of predictability of outcome in this complex and highly contentious process. However, this Court has not accorded weight to the Board's findings regarding the assessed value of TAPS in those subsequent years given the Owners' observation that to do so creates a degree of circularity that could impact the nature of this trial de novo for the 2007 through 2009 tax years.

50. James Greeley became the State Petroleum Property Assessor in 2007. No disparity or inequality in valuation methodology among AS 43.56 pipelines has been demonstrated during the lien years. There is no basis in the record to support a claim that the 2007, 2008, or 2009 TAPS assessment violates the equal protection clause under either the state or federal Constitution, or is otherwise impermissibly discriminatory.

51. The Court found in the 2006 tax year proceedings that the Department did not abruptly and without notice change its policy to consider the cost approach for the first time in 2005.[77] This Court again so finds with respect to the 2007 through 2009 tax years.

52. The Department's use of the cost approach does not constitute a "de facto regulation." The applicable regulation has expressly permitted reliance on a cost approach for over three decades.[78]

53. The record does not support a claim that the 2007, 2008, or 2009 assessment violates the due process clause of either the state or federal Constitution.

---

[77] *See* Amended Decision ¶ 63.

[78] 15 AAC 56.110(c).

III. DESCRIPTION OF THE PROPERTY

A. Ownership

54. As of January 1 for each of the three tax years at issue, TAPS was owned by BP Pipelines (Alaska) Inc. (46.9%), ConocoPhillips Transportation Alaska, Inc. (28.3%), ExxonMobil Pipeline Company (20.3%), Koch Alaska Pipeline Company (3.1%), and Unocal Pipeline Company (1.4%).[79] Alyeska Pipeline Service Company ("Alyeska") is the operating agent for the Owners.[80]

55. TAPS is physically a single pipeline, but there are effectively five different pipelines because each TAPS Owner has an undivided ownership interest in TAPS. This ownership structure permits each individual Owner to use its portion of TAPS as part of the vertically integrated business operations of that Owner's affiliates. Each TAPS Owner maintains a separate tariff and each accepts nominations to its undivided ownership interest.[81]

56. Each Owner's entitlement to a portion of the pipeline's capacity or "space" is established under the Amended Capacity Settlement Agreement ("ACSA"), which together with the TAPS Operating Agreement provides that each Owner's share of pipeline capacity is equal to the pipeline ownership percentage multiplied by TAPS' capacity, which for each of the lien years was 1.1 million bbl/d.[82]

---

[79] MUN7-0001 at 485; MUN7-0800 at 15.

[80] MUN7-0001 at 485; MUN7-0800 at 15.

[81] MUN7-0001 at 977 (Coulson); Tr. 8357-58, 8550 (Cicchetti).

[82] MUN7-0001 at 982-83 (Coulson).

B. Physical Description

57. TAPS is an 800-mile long, 48-inch diameter crude oil pipeline system that crosses three mountain ranges and over 800 rivers and streams during its traverse from the Alaska North Slope ("ANS") oil fields to the Valdez Marine Terminal ("VMT").[83] TAPS consists of the right-of-way, pipe, pumps, tanks, tanker loading facilities and associated equipment.[84] Approximately 420 miles of the 800-mile pipeline are aboveground and supported by 39,000 pairs of Vertical Support Members ("VSMs").[85] TAPS is the only pipeline transporting crude oil from the ANS, and is therefore a basin-opening transportation system. As of each lien date, there was no other viable transportation alternative to carry significant quantities of oil from the ANS to market.[86]

58. TAPS' taxable property includes only the tangible real and personal property from Pump Station 1 through the VMT and does not include intangible property, marine tankers, refineries, ANS proven reserves, ANS crude oil, ANS exploration property, or any property that is upstream of Pump Station 1.[87]

C. Original Construction and Strategic Reconfiguration

59. Construction of TAPS began in 1974 and was completed in the summer of 1977. It required 515 federal permits and 832 state permits.[88] There were 14 airfields of varying lengths built to support the construction of TAPS.[89] The construction workforce

---

[83] MUN7-0001 at 965 (Coulson).

[84] Tr. 11751-11752 (Remsha).

[85] MUN7-0001 at 520, 547, 549.

[86] Tr. 8916 (Cicchetti); MUN7-01 at 3767 (Coulson).

[87] Tr. 529 (Remsha); Tr. 12903 (Greeley).

[88] MUN7-0001 at 502.

[89] MUN7-0001 at 484.

totaled approximately 70,000 employees, with a peak number of 28,000 employees working in October 1975.[90] At the time of its construction, TAPS was the largest privately funded construction project in U.S. history.[91] Before construction began, the estimated cost was set at $863 million. However, when finally completed in 1977, the final cost of TAPS was nearly ten times greater, at approximately $8 billion.[92]

60. The initial design capacity for TAPS in August 1970 was 600,000 barrels per day ("bbl/d") of throughput.[93] In July 1974, the design capacity was increased to 1.2 million bbl/d.[94] And soon after it was again adjusted to 1.42 million bbl/d.[95]

61. "Pursuant to an agreement among the TAPS carriers dated March 29, 1979, the Owners have utilized a chemical drag reduction known as 'DRA' to increase throughput in excess of TAPS' 1.42 million [bbl/d] design capacity."[96]

62. After the use of DRA was implemented, TAPS was able to transport 2.1 million bbl/d at its peak production in 1988. After peaking in the late 1980s, throughput on TAPS has gradually reduced. As of the January 1, 2007, 2008, and 2009 lien dates, the Department of Revenue estimated production of ANS crude oil and natural gas liquids ("NGLs") at 740,000 bbl/d for fiscal year 2007, at 731,000 bbl/d for fiscal year 2008, and at 691,000 bbl/d for fiscal year 2009.[97]

---

[90] MUN7-0001 at 489.

[91] MUN7-0001 at 965 (Coulson).

[92] MUN7-0001 at 488.

[93] MUN7-0215 at 11. *See also* Tr. 7058 (Ray).

[94] MUN7-0215 at 62.

[95] TO-07-0179.0130. *See also* MUN7-0001 at 2026.

[96] TO-07-0190.0001 (FERC Order Approving Agreement, issued May 15, 1998).

[97] MUN7-0018 at 13, 20, 27. *Cf.* TO-07-0004 at 78, 111, 126.

63. The first oil began to flow through TAPS on June 20, 1977. The first tanker of crude oil left the VMT on August 1, 1977. At that time, ANS proven reserves were estimated at approximately 9.6 billion barrels. As of January 1, 2007, over 15 billion barrels of oil had been transported through TAPS.[98]

64. TAPS' design capacity of 1.42 million bbl/d has not been changed, except that a strategic reconfiguration ("SR") project of the pumps has been undertaken over the past several years. In that project, some of the original Legacy pumps have been taken out of service and others have been replaced with new variable speed pumps. The current physical capacity of the operating pumps on TAPS is 1.1 million bbl/d.[99] The mechanical capacity of those pumps is 760,000 bbl/d. Adding DRA to the oil increases the ability of the upgraded SR pumps to transport up to 1.1 million bbl/d. Alyeska has described the goal of SR as follows: "to position TAPS for more effective operation while maintaining or enhancing safety, operational integrity and environmental performance. The new system is modular and scalable and will provide flexibility for future increases or decreases in throughput."[100]

65. Jeff Ray of ExxonMobil Pipeline Company testified that the Owners are not currently maintaining 1.1 million bbl/d of physical capacity because two of the DRA injection sites can only use an older form of DRA. However, Mr. Ray also indicated that those two sites could be quickly modified to be able to use the newer DRA for "probably a couple million dollars," which would then bring the physical capacity to 1.1 million bbl/d.[101] Accordingly, this Court finds that TAPS' physical capacity during each of the lien years,

---

[98] TO-07-0004.0408.

[99] MUN7-0215 at 107; Tr. 7037 (Ray).

[100] MUN7-1103 at 56. *See also* Tr. 2728-30 (Falcone).

[101] Tr. 7049-51 (Ray).

including its SR pumps and with DRA, was 1.1 million bbl/d. The design capacity of the mainline pipe and the VMT remained at 1.42 million bbl/d during each of the lien years.

D. Limited-Market Property

66. TAPS is a limited-market property because there is a very limited market for the purchase and sale of any ownership interest in TAPS. When interests in TAPS have changed hands, the buyers have purchased those interests as part of a broader transaction that has included the buyers' use of TAPS to transport ANS product to market. Each of the Owners has a right of first refusal should any other Owner elect to sell its interest in TAPS.[102]

67. TAPS' limited market or market participants are best defined as the shippers on TAPS – the ANS producers. It is these producers that would pay for TAPS, or if hypothetically TAPS did not exist as of the assessment dates, would pay to build or replace TAPS.[103]

E. Special-Purpose Property

68. TAPS is also a special-purpose property. It was specifically designed, constructed, and adapted for its particular use – to move affiliated crude oil from the ANS to Valdez. The ANS represents about 15% of the U.S. domestic crude oil production and TAPS is the only viable means of transporting that oil to market.[104]

F. Integrated Economics

69. The TAPS Owners did not and could not have independently financed the original construction of TAPS and they do not independently finance substantial

[102] Tr. 11355-56 (Podwalny); Tr. 11903 (Remsha).

[103] Tr. 11978 (Remsha); Tr. 12798 (Greeley).

[104] MUN7-0001 at 410; Tr. 8206-07, 8211 (Cicchetti).

improvements to TAPS. Instead, the affiliated production companies have financed TAPS' construction. And the evidence at trial demonstrated that all significant funding decisions for TAPS are not made by the TAPS Owners, but by the affiliated parent corporations or upstream producer affiliates of each Owner.[105]

70. As of the lien dates, the parent companies of the three largest owners of TAPS (BP, ConocoPhillips, and ExxonMobil) had a combined 95% ownership interest in TAPS.[106] These same three parent companies also had a combined total in excess of 96% of the estimated production on the North Slope.[107] This close correlation between estimated production and ownership interest in TAPS is expected to remain in place for the foreseeable future.[108] One of the other two TAPS Owners, Unocal, has an affiliate (Chevron) with substantial ANS production. The other TAPS Owner, Koch Alaska Pipeline Company, has an affiliate whose contract with the State provides it with oil for delivery to the largest refinery connected to TAPS (Flint Hills). Thus, each of the five TAPS Owners has an affiliate with oil to be transported on TAPS.[109]

71. Each Owner's affiliated producer has an economic incentive to nominate its ANS production to its affiliated TAPS Owner. As explained by Charles Coulson, the President of BP Pipelines:

> There has been a strong pattern of shippers on TAPS nominating their barrels to affiliated pipeline companies. There are a variety of reasons for this behavior, but mostly it can be understood by thinking about integrated corporate economics. When an upstream affiliate

---

[105] *See, e.g.*, Tr. 2708-09 (Falcone)

[106] Tr. 8550 (Sullivan). *See also* MUN7-0001 at 983 (Coulson).

[107] Tr. 8551 (Sullivan); MUN7-0001 at 971 (Coulson).

[108] MUN7-0001 at 984 (Coulson); Tr. 9272-74 (Platt).

[109] MUN7-0001 at 984 (Coulson).

> ships barrels in its pipeline affiliate's space, it pays the published tariff rate to the pipeline affiliate, and no money leaves the corporate family.[110]

72. In addition to serving as President of BP Pipelines, Mr. Coulson is Vice President of BP Shipping US. He explains, "those two roles allow me to manage BP's midstream assets here in Alaska."[111] Mr. Coulson's paycheck is from BP Exploration (Alaska), Inc. ("BPXA"); BP Pipelines does not maintain any bank accounts.[112] Accordingly, the TAPS tariffs that BP Pipelines collects are not paid to it but to another BP affiliate.[113] And if Alyeska proposed that the Owners expend money for a large project on TAPS, Mr. Coulson testified that BP would assess whether it fits with "what we want to do in Alaska corporately,"[114] with funding determinations for TAPS made by BP's upstream executive group.[115]

73. And yet while four of the five Owners are vertically integrated oil companies, there is no evidence that they operate collusively together as an economic unit or in concert with other producing or refining entities as an economic unit. Likewise, the proven reserves owned by an affiliate of one TAPS Owner are not integrated with the proven reserves of an affiliate of another TAPS Owner or with the proven reserves of an unaffiliated producer.[116]

---

[110] MUN7-0001 at 984 (Coulson FERC Testimony, April 13, 2010). *See also* MUN7-0001 at 2411 (Jaffe Affidavit) ("The movement of petroleum through the pipeline is dominated by shipments in which the shipper is among the corporate affiliates of the carriers."); Tr. 7728-7729 (Toof); Tr. 8195 (Cicchetti).

[111] MUN7-0001 at 3717.

[112] MUN7-0001 at 3740.

[113] MUN7-0001 at 3749.

[114] MUN7-0001 at 3753.

[115] MUN7-0001, 3751-53.

[116] Tr. 7391 (Falcone).

G. Unique Regulatory Status

74. TAPS is a regulated pipeline, regulated by both the Regulatory Commission of Alaska ("RCA") and the Federal Energy Regulatory Commission ("FERC").

75. During the first several years of TAPS' operation, the amount of the tariff was in litigation. In 1985, the Owners and the State entered into the TAPS Settlement Agreement ("TSA"). For the next two decades, the tariffs were based on the TAPS Settlement Methodology ("TSM") and were not evaluated under the just and reasonable standard.[117] The TSM front-end loaded the recovery of the initial cost of TAPS to such a degree that the original investment was largely recovered by the late 1990s – decades before any reasonable estimate of the end of TAPS' economic life.[118]

76. The TSM also allowed an accelerated recovery of return in the form of an allowance per barrel. The RCA held that the TSM resulted in $9.9 billion (nominal dollars) or $13.5 billion (1997 dollars) more than would otherwise have been permitted under traditional cost of service regulation.[119] The higher tariffs during that time also resulted in lower production tax liability for the affiliated producers.

77. The TSA expired in 2005. Since then, there has been considerable litigation before FERC and the RCA with respect to the TAPS tariffs.

---

[117] *BP Pipelines (Alaska), Inc.*, 119 F.E.R.C. ¶ 63,007 at ¶¶ 48, 54 (2007).

[118] Tr. 8567 (Sullivan).

[119] Tr. 8567 (Sullivan); MUN7-0001 at 1274.

IV. PREMISE OF VALUE

78. A premise (or standard) of value is included in all assessments and appraisals of property.[120]

79. The statutory premise of value in AS 43.56.060(e)(2) was interpreted by this Court in the Amended Decision.[121] Although this Court vacated the August 8, 2011 Collateral Estoppel Order for the 2007 through 2009 tax years and allowed the parties to present additional evidence and arguments regarding the premise of value at the trial de novo, this Court has not been persuaded that the conclusions reached by this Court in the Amended Decision regarding the premise of value should be abandoned, but has determined that they should be further refined as discussed herein. Further, this Court has also more thoroughly studied the legislative history of the statute as discussed below.

80. The terms "economic value" and "full and true value" have no generally accepted definitions in the appraisal profession.[122]

81. Different concepts of value arise from economic principles, including the concepts of value in exchange and use value.[123] Value is never a fact but always an opinion of worth at a given time in accordance with a definition of the standard of value.[124]

82. Value in exchange is also referred to as market value.[125] This concept generally is expressed as the amount that a willing buyer will pay and a willing seller will

---

[120] American Society of Appraisers, *Valuing Machinery and Equipment: The Fundamentals of Appraising Machinery and Technical Assets* 2 (2d ed. 2005) [hereinafter *Valuing Machinery and Equipment*].

[121] Amended Decision ¶ 95.

[122] Tr. 11897-10 (Remsha); Tr. 12203, 12230-31 (Marchitelli). *See also* Amended Decision ¶ 64.

[123] *See generally* Appraisal Institute, *The Appraisal of Real Estate* 15-32.

[124] Tr. 513-14 (Remsha).

[125] *The Appraisal of Real Estate* at 23.

accept, in an arm's length negotiation, to transfer the property, with both buyer and seller being knowledgeable about the property.[126] Market value is a transactional-based concept.[127]

83. "Use value is the value a specific property has for a specific use. In estimating use value, the appraiser focuses on the value the real estate contributes to the enterprise of which it is a part without regard to the highest and best use of the property or the monetary amount that might be realized from its sale."[128] "If a property's current use is so specialized that there is no demonstrable market for it but the use is viable and likely to continue, the appraiser may render an opinion of use value if the assignment reasonably permits a type of value other than market value. Such an estimate should not be confused with an opinion of market value."[129]

84. Market value and use value can be the same value if the highest and best use of the property is its current use.[130]

85. Use value is distinct from investment value. "Investment value is the value of a property to a particular investor based on that person's (or entity's) investment requirements. In contrast to market value, investment value is value to an individual, not necessarily value in the market."[131] *The Appraisal of Real Estate* describes investment value as a "subjective"

---

[126] *The Appraisal of Real Estate* at 23.

[127] *The Appraisal of Real Estate* at 22-25.

[128] *The Appraisal of Real Estate* at 27. "The term 'value in use' is often used by appraisers synonymously with 'use value,' but the former term has specific meanings in other contexts, which can cause confusion." *The Appraisal of Real Estate* at 28.

[129] *The Appraisal of Real Estate* at 28.

[130] Tr. 408 (Swain); Tr. 508-09, 515 (Remsha); Tr. 10342-48 (Tegarden); Tr. 12209 (Marchitelli); Tr. 12962-3 (Greeley); Tr. 958 (Eyre); Tr. 875 (Podwalny); Tr. 11632-33 (Hoffbeck).

[131] *The Appraisal of Real Estate* at 28-29.

type of value, and this Court has not interpreted the applicable statute as creating an investment value standard.

86. The Legislature's references in AS 43.56.060(e)(2) to "full and true value" and "economic value," along with its omission of the terms "open market," "willing seller and willing buyer," and "the estimated price that the property would bring in an open market," reflect an intent to accord flexibility to the Division and SARB when valuing pipeline property, particularly unique pipeline property like TAPS.[132]

87. That the Legislature could have required, but chose not to require, that the premise of value for pipeline property be a market value standard, lies in its omission of the terms "open market" and "willing seller and willing buyer" to describe the premise of value for such property – in contrast to its use of those terms for other property such as exploration property under AS 43.56.060(c).[133]

88. That AS 43.56.060(e) does not mandate a market value standard for the valuation of pipeline properties is fully supported by the legislative history.

89. In October 1973 two parallel bills, HB 1 and SB 1, were introduced by Governor Egan during a special session of the Alaska Legislature.[134] A version of HB 1 was

[132] The rule of statutory construction that where a form of conduct, the manner of its performance and operation, and the persons and things to which it refers is expressly designated, there is an inference that all omissions should be understood as exclusions clearly is applicable here. *See, e.g.,* Norman J. Singer and J.D. Shambie Singer, 2A *Sutherland Statutory Construction* § 47:23 at 417 (7th ed. 2007) ("The force of the maxim is strengthened where a thing is provided in one part of the statute and omitted in another.") (citation omitted). *See also Ranney v. Whitewater Engineering*, 122 P.3d 214, 218-19 (Alaska 2005); *Croft v. Pan Alaska Trucking, Inc.*, 820 P.2d 1064, 1066 (Alaska 1991) (explaining that application of this principle of statutory construction "is particularly compelling where, as here, the scheme is purely statutory and without a basis in the common law"). *Cf.* Owners' Proposed Findings of Fact and Conclusions of Law ¶ 29. The parenthetical referencing of Sutherland's 6th Edition that is set forth in that proposed finding could not be located in that treatise.

[133] *See also* AS 29.45.110(a).

[134] H.J. at 4-6, 8th Leg., 1st Spec. Sess. (Alaska 1973) (letter from William A. Egan introducing HB 1); S.J. at 4-5, 8th Leg., 1st Spec. Sess. (Alaska 1973) (letter from William A. Egan introducing SB 1).

ultimately passed by the Legislature as the oil and gas property taxation statutes, AS 43.56.010 *et seq.*[135]

90. At the time of the special session, pipeline construction was imminent. Other bills had been introduced the previous year but failed to make it out of committee.[136] The 1973 legislative history demonstrates a tangible awareness of the time constraints imposed by the special session.[137]

91. Likely as a function of this time pressure, committee discussions of HB 1 were not always precise. On occasion, they blurred distinctions between methods of valuation, standards of valuation, depreciation bases, and types of property.

92. Much of the discussion surrounding HB 1 focused on the destination of the tax revenue and concerns about the creation of new "pipeline boroughs." The legislative history of AS 43.56.060 is not extensive, but what does exist is indicative of a legislative intent to give assessors the tools and flexibility so as to permit assessed valuations to be increased over time, as warranted.[138]

---

[135] Specifically, a Senate Free Conference Committee substitute for a Senate Finance Committee Substitute for a House Finance Committee substitute for HB 1 was enacted. S.J. at 129.

[136] HB 460 [2007 R. 9472]; HB 598 [2007 R. 9492].

[137] *See, e.g.*, *Minutes* at 88, H. Comm. Community and Regional Affairs, 8th Leg., 1st Spec. Sess. (Alaska 1973) (Nov. 3, 1973) (Committee Report on Senate CS for CS for HB 1) ("There is no doubt also that we could produce a better bill if we had more time . . .") [2007 R. 9845]; *Minutes* at 139, S. Finance Comm., 1st Spec. Sess. (Alaska 1973) (Nov. 8, 1973) ("Sen. Palmer noted the effect of [the assessment] section was several years down the line, and he thought it would be more expedient to accept the House version at this time.") [2007 R. 9861]; *Minutes* at 10, S. Free Conference Comm., 1st Spec. Sess. (Alaska 1973) (Nov. 10, 1973) (Rep. Freeman presented the Committee's options as "deadlock" or "accept[ing] the mediocre bill before them"; within an hour, the Committee adopted the bill version that became the statute.) [2007 R. 9871].

[138] See, *e.g.*, *Minutes* at 21, H. Finance Comm., 8th Leg., 8th Leg., 1st Spec. Sess. (Alaska 1973) (Oct. 20, 1973) ("Mr. Condon, Assistant Attorney General, answered that with respect to production property, the value would be less using that approach. With respect to the pipelines, they use actual cost depreciation on an annual straight line allowance with no inflation factor. He said their pipeline formula would tend to lead to higher valuation.") [2007 R. 9708]; *Minutes* at 22, H. Finance Comm., 1st Spec. Sess. (Alaska 1973) (Oct. 20, 1973) ("Mr. Fink said valuations of this type of property seem difficult. He asked whether they couldn't take advantage of increased value.") [2007 R. 9710].

93. The Owners assert that at the time AS 43.56.060 was drafted, "economic value" was consistent with "market value" and that "the term economic value was at least partially familiar to legislators as being a reference to an assessment methodology using an income stream."[139] The Court finds this argument unavailing. In support of this assertion, the Owners cite to a sentence in a memorandum by a fiscal analyst to the Speaker of the House of Representatives dated October 17, 1973, prior to the House taking up HB 1.[140] The sentence reads: "Various methods and factors can be considered in arriving at assessed value including actual cost and the economic value or income stream the line is capable of producing."[141] The memo makes no reference to market value.[142]

94. AS 43.56.060 contains different definitions of "full and true value" for different types of property. In general terms, it specifies market value for exploration property, use of replacement cost less depreciation for production property, and economic value for transportation (pipeline) property.

95. In its original form, HB 1 set forth three approaches for the three types of property. Language that was not retained in the bill as finally enacted into AS 43.56.060 is italicized:

- Exploration property was to be assessed using market value: "the estimated price which the property would bring in an open market and under the then prevailing market conditions in a sale between a willing seller and a willing

---

[139] Owners' Proposed Findings of Fact and Conclusions of Law ¶¶ 26, 35.

[140] R. 9922-23.

[141] R. 9922-23.

[142] R. 9922-23.

buyer both conversant with the property and with prevailing general price levels."[143]

- Production property was to be assessed "on the basis of *actual cost* less depreciation based on *units of production*."[144]

- Transportation property was to be assessed "with due regard to the economic *life* of the property based on the estimated life of the proven reserves of gas or unrefined oil then technically, economically and legally deliverable into the transportation facility."[145]

96. The assessment of production and transportation property received most of the attention in legislative deliberations. The minutes reflect that Attorney General John Havelock was actively involved with earlier versions of the bill,[146] was present at many of the House and Senate committee meetings, and the majority of the committees' valuation questions were directed to him.

97. HB 1 was referred to the House Finance Committee on October 17, 1973.[147] The House Finance Committee substitute ("HFCS") was adopted by the House on October 29, 1973.[148]

98. The House Finance Committee minutes indicate that the Committee considered and rejected both a market value approach and a reliance on the pipeline's value for rate regulation purposes for assessing transportation property.

---

[143] H.B. 1, 8th Leg., 1st Spec. Sess. (Alaska 1973) [2007 R. 9645].

[144] H.B. 1, 8th Leg., 1st Spec. Sess. (Alaska 1973) [2007 R. 9645].

[145] H.B. 1, 8th Leg., 1st Spec. Sess. (Alaska 1973) [2007 R. 9645].

[146] *See, e.g.*, 2007 R. 9541 (Attorney General Havelock answering questions about HB 59, a predecessor bill, before the House Resources Committee earlier in 1973) (specific date unavailable).

[147] H.J. at 4, 8th Leg., 1st Spec. Sess. (Alaska 1973) (Oct. 17, 1973) [2007 R. 9903].

[148] H.J. at 58, 8th Leg., 1st Spec. Sess. (Alaska 1973) (Oct. 29, 1973) [2007 R. 9911].

99. The minutes also indicate that the Committee considered an actual cost valuation and a units-of-production depreciation method. At a hearing, Homer Burrell, then Director of the Division of Oil and Gas, asked the Committee, "How can you determine the full and true value of a $4 billion installation." One representative indicated that "the actual cost of construction conceivably could be the full and true value. Original construction costs could be used, and appreciated or depreciated accordingly." Mr. Burrell responded: "this apparently allows for inflation and deflation but that is all. When the oil is gone, [the pipeline] is worthless, although it still could be appraised at $4 billion. Units of production tie [the pipeline] to its economic life, but its physical life must be considered also." Mr. Burrell indicated that the uncertainty lay with whether the pipeline's physical life would be shorter or longer than its economic life. He added, "units of production depreciation covers the pipeline as long as there is oil going through it."[149]

100. When the subject of market value was raised, Attorney General Havelock's response was focused on production property:

> Mr. Fink referred to the method of valuation. He noted they had heard testimony and a good argument made for value of property at fair market value as opposed to their method. He wondered whether the method would make much difference.
>
> Mr. Havelock replied it would be a considerable change. The fair market value method would introduce an element of uncertainty in property that doesn't have a fair market value. He said the question was whether they were going to valuate production equipment on fair market value and create considerable uncertainty because there was not the same kind of market in production facilities. He asked how they would figure fair market value excluding intangibles that would go into the price. He didn't think the fair market value was appropriate,

[149] *Minutes* at 50, H. Finance Comm., 8th Leg., 1st Spec. Sess. (Oct. 22, 1973) [2007 R. 9735].

> and added that from the industry point of view it would give uncertainty because it would depend on the assessor.[150]

101. The House Finance Committee also discussed reliance on the pipeline's value for regulatory purposes, or "the ICC approach," so named after FERC's predecessor agency, the Interstate Commerce Commission.[151] The Committee minutes indicate that the approach was dismissed by Attorney General Havelock:

> Mr. Malone asked if it wouldn't simplify things if they just used the valuation placed on the pipeline for return by ICC. Mr. Havelock said no . . . Mr. Malone thought it would simplify the State's assessment procedure and put it on a parity with the tarrif [sic]. Mr. Havelock didn't think the State's problem was that complex.[152]

102. In this regard Larry Eppenbach, Deputy Commissioner of the Treasury, stated:

> Mr. Fink asked whether Mr. Eppenbach thought the value of the pipeline would go down over fifty years. Mr. Eppenbach believed ICC will reduce valuation from time to time and not increase it. . . . Mr. Eppenbach said that every indication they got was that ICC would reduce the value.[153]

103. Thus, the legislative history supports a conclusion that the House specifically considered and rejected an assessed value standard equal to the pipeline's value for rate-making purposes.

104. During the same legislative session at which HB 1 was introduced, an alternate bill, HB 9, was introduced to the House on October 22, 1973 and referred to the

---

[150] *Minutes* at 21, H. Finance Comm., 8th Leg., 1st Spec. Sess. (Alaska 1973) (Oct. 20, 1973) [2007 R. 9708].

[151] *Minutes* at 21, H. Finance Comm., 8th Leg., 1st Spec. Sess. (Alaska 1973) (Oct. 20, 1973) [2007 R. 9708].

[152] *Minutes* at 23-24, H. Finance Comm., 8th Leg., 1st Spec. Sess. (Alaska 1973) (Oct. 20, 1973) [2007 R. 9711-12].

[153] *Minutes* at 22-24, H. Finance Comm., 8th Leg., 1st Spec. Sess. (Alaska 1973) (Oct. 20, 1973) [2007 R. 9710-12].

House Finance Committee.[154] HB 9 addressed exploration, production, and transportation property together in a single provision, and provided that the full and true value of all three types of property would be "the estimated price which the property would bring in an open market and under the then prevailing market conditions in a sale between a willing seller and a willing buyer both conversant with the property and with prevailing general price levels."[155] The House Finance Committee minutes do not reflect any discussion of HB 9, suggesting that the House was not interested in a unilateral market value approach to value the three different types of property.

105. After its adoption by the House on October 29, 1973, HFCS was sent to the Senate Finance Committee, which produced a committee substitute ("SFCS") that was forwarded to the Senate on November 8, 1973.

106. SFCS contained the final language for the ad valorem assessment of transportation property that appears in AS 43.56.060(e). It trimmed down HFCS by removing the "replacement cost" component added by the House, and substituted "economic value" for "economic life" for transportation property.[156] The following excerpts from the Senate Finance Committee minutes are informative:

> Referring to sub-section (2), page 5, line 7, Sen. Groh said the House version used replacement costs less depreciation versus the original version which used actual costs. Sen Palmer said this approach was used in the Kenai borough and it appeared satisfactory. Sen. Palmer moved the adoption of the House version. Sen. Groh noted there was

[154] H.J. at 25, 8th Leg., 1st Spec. Sess. (Alaska 1973) (Oct. 22, 1973). Another bill, HB 10, was introduced October 25, 1973, and adopted the assessment language of HFCS wholesale. H.J. at 34, 8th Leg., 1st Spec. Sess. (Alaska 1973) (Oct. 25, 1973); H.B. 10, 8th Leg., 1st Spec. Sess. (Alaska 1973) (offered Oct. 25, 1973) [2007 R. 9635-37].

[155] H.B. 9, 8th Leg., 1st Spec. Sess. (Alaska 1973) (offered Oct. 22, 1973) [2007 R. 9629].

[156] Senate CS for CS for HB 1, S. Finance Comm., 8th Leg., 1st Spec. Sess. (Alaska 1973) (offered Nov. 8, 1973) (emphasis added) [2007 R. 9667].

> a substantial difference between Kenai and a $4.5 billion pipeline, and the committee discussed which version should be adopted. Sen Lewis moved to replace the word "replacement" with "actual." Sen. Ray said fair market value would be more appropriate. Sen. Groh referred to the motion made by Sen. Lewis [to change "replacement" to "actual"], and Sen. Palmer asked that the record show the vote on this now was no commitment to the future. The motion passed by a vote of 4 to 3.
>
> . . .
>
> Sen. Groh asked if there were any other suggestions regarding CSHB 1, and Sen. Ray said there were still problems with actual versus replacement costs. After discussion, Sen. Palmer noted the effect of this section was several years down the line, and he thought it would be more expedient to accept the House version at this time. Mr. Havelock said the Governor's version had different language, and the House version would not produce as much revenue. Sen. Palmer moved to rescind the committee's previous action [replacing "replacement" with "actual"]; upon vote the motion was accepted by a vote of 4 to 3. Sen. Butrovich moved and asked unanimous consent to adopt the Governor's wording ["with due regard to the economic life of the property"] in this section, and then amended his motion to include substituting "economic value" for "economic life." No objection, so ordered.[157]

107. Although the details of this deliberative process are difficult to discern, what can be gleaned from this otherwise opaque account is that the Senate Finance Committee did not seriously consider a market value approach, as it was mentioned only in passing and not voted upon.[158]

108. Based on this Court's review of the legislative history, an ICC-based or regulatory valuation was not discussed in the Senate.

[157] *Minutes* at 138-39, S. Finance Comm., 8th Leg., 1st Spec. Sess. (Alaska 1973) (Nov. 8, 1973) [2007 R. 9860-61].

[158] *Minutes* at 138-39, S. Finance Comm., 8th Leg., 1st Spec. Sess. (Alaska 1973) (Nov. 8, 1973) [2007 R. 9860-61] ("Sen. Ray said fair market value would be more appropriate.").

109. The bill then went to a Free Conference Committee.[159] There, the House attempted to negotiate a return to "replacement cost" instead of "economic value" for the valuation of pipeline property in exchange for other concessions, but was unsuccessful.

110. The legislative history demonstrates that the House had a preference for valuing transportation property using an explicit "replacement cost" approach, while the Senate preferred an apparently less restrictive "economic value" approach, which Attorney General Havelock had advised Legislators would produce more revenue, and in the end, the Senate prevailed on this issue.

111. In its closing argument at the trial de novo before this Court, the Department stated that the legislative history, taken as a whole, "demonstrates some likelihood that the Legislature was fully cognizant of a willing buyer/willing seller standard when it enacted 43.56.060(e)(2)."[160] This Court agrees and further finds that the Legislature was also cognizant that the pipeline would be valued by the ICC for rate making purposes, and did not adopt such a premise for ad valorem tax purposes.

112. The Owners assert that the "Alaska tax system will not function properly if a pipeline valuation methodology is adopted that does not take governmentally established tariff levels into account."[161] They maintain that because the production tax is computed after the deduction of pipeline tariffs, "TAPS property tax value must take into account actual tariff income."[162] To do otherwise, the Owners maintain, "whipsaws North Slope producers

---

[159] H.J. at 140, 8th Leg., 1st Spec. Sess. (Alaska 1973) (Nov. 10, 1973) [2007 R. 9913].

[160] Tr. 13272-73 (Department's closing).

[161] Owners' Proposed Findings of Fact and Conclusions of Law ¶ 787.

[162] Owners' Proposed Findings of Fact and Conclusions of Law ¶ 786.

and pipeline transportation companies, taxing pipeline companies as if they received high tariff income but taxing producers as if they incur low tariff expense."[163]

113. But this Court finds that valuing the pipeline without exclusive reliance on the tariff income does not result in taxing the pipeline companies as if they received a high tariff income. Rather, an assessed valuation that exceeds the net present value of the projected tariff income stream recognizes that the value of the pipeline exceeds that tariff income stream. This Court has previously determined, and again holds, that "the term 'economic value' as set forth in AS 43.56.060(e)(2) does not mandate, as a matter of law, the exclusive reliance on the regulated tariff income to value TAPS."[164]

114. In the case of TAPS, AS 43.56.060(e)(2)'s reference to "economic value" and not "market value" is consistent with the reality that there is no market for TAPS as a stand-alone investment based solely on its tariff income. Even if there might be a buyer of TAPS based solely on its tariff income, the evidence at the trial de novo conclusively demonstrated that a TAPS Owner would not sell its interest in TAPS without the assurance that its affiliated oil from the Alaska North Slope could be shipped to market. At trial, the Owners' appraisal expert Michael Remsha was asked if he believed that the TAPS Owners would sell TAPS to a "rich sheikh from Saudi Arabia"[165] for $20 billion "for the expressed purpose of shutting [TAPS] down."[166] Mr. Remsha replied that the Owners would "[m]ost likely not" sell

[163] Owners' Proposed Findings of Fact and Conclusions of Law ¶ 786.

[164] *See* Order on Summary Judgment Motions at 5 (Sept. 24, 2007).

[165] Tr. 690 (Remsha).

[166] Tr. 692 (Remsha).

their interests in TAPS at that price under those circumstances, "[b]ecause they want to be able to have the opportunity to take oil from the North Slope and bring it to market."[167]

115. Highest and best use generally considers the most probable use that is physically possible, legally permissible, financially feasible, maximally productive, and results in the highest value.[168] The purpose of a highest and best use analysis is to evaluate alternative uses to assist the appraiser in determining the use which creates the highest value of the property.

116. A highest and best use analysis is not required to be made when valuing property under non-market value standards, including a use value standard, because a use value appraisal is literally valuing the current use.[169] Nonetheless, a highest and best use analysis can be helpful in considering the full and true value of TAPS. "The highest and best use of special-use property as improved is probably the continuation of its current use if that use remains viable."[170] The highest and best use of TAPS is its current use – the transport of ANS oil to market.[171] This use is physically possible, legally permissible, and maximally productive. TAPS would not provide maximum value on a standalone basis.

117. The fee simple interest, as an analytical tool, includes the full bundle of rights subject only to the four powers of government: police power, escheat, eminent domain, and taxation.[172] The taxable property does not include any external interest held by third parties

---

[167] Tr. 692 (Remsha).

[168] *The Appraisal of Real Estate* at 278; *Valuing Machinery and Equipment* at 212.

[169] Tr. 12536 (Goodwin).

[170] *The Appraisal of Real Estate* at 294.

[171] Tr. 692 (Rein); Tr. 8196 (Cicchetti); MUN7-0001 at 3767 (Coulson).

[172] *The Appraisal of Real Estate* at 122.

who are not TAPS Owners, including any alleged "Shippers' interests."[173] When valuing TAPS for ad valorem tax purposes, the only interests that are valued are the TAPS Owners' undivided fee simple property interests in TAPS' taxable property. The right of a shipper to transport crude oil in a common carrier pipeline does not transfer a portion of the pipeline owner's fee simple property interest to that shipper.[174]

118. TAPS is a regulated common carrier pipeline and must accept and transport tendered oil for transportation without discrimination.

119. The Owners have asserted that the government regulation of the rates for transport on TAPS is a form of police power that diminishes the value of TAPS.[175] Regulation may diminish the value of the regulated property.[176] But as several witnesses testified at the trial, regulation may also have no effect on a property's value or increase its value.[177] This Court has previously held and again finds that an assessment must consider the extent to which the exercise of police power or any other governmental power impacts the value of the particular property being assessed. The Owners presented Professor Swain, Mr. Tegarden, and Mr. Marchitelli as theory witnesses, none of whom offered an opinion on whether regulation resulted in an increase or decrease in TAPS' ad valorem value, but indicated that the effects of rate regulation had to be taken into account.[178]

---

[173] Tr. 12204-05 (Marchitelli).

[174] Tr. 12205-08 (Marchitelli). *Cf.* Tr. 12915-17 (Greeley).

[175] In this regard, the Owners appear to substantially misquote the definition of police power from *The Appraisal of Real Estate* in their proposed findings. The definition from that text does not identify either "income restrictions" or "rate regulations" as forms of police power. *Compare* Owners' Proposed Finding ¶ 789 *with The Appraisal of Real Estate* at 122.

[176] *Wash. Gas Light Co. v. Baker*, 188 F.2d 11, 19 (D.C. Cir. 1950) (citing *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 601 (1944)).

[177] Tr. 447 (Swain); Tr. 10318-10320 (Tegarden); Tr. 12258 (Marchitelli).

[178] Tr. 449 (Swain); Tr. 10318-10320 (Tegarden); Tr. 12261:25-12262:14 (Marchitelli).

120. Assuming, without deciding, that rate regulation is a form of police power, it does not alter the premise of value for TAPS, nor does it require that TAPS be valued for ad valorem tax purposes at the net present value of its projected tariff income. Rather, it requires the assessor to consider whether and to what extent rate regulation impacts the value of TAPS. Under a cost approach to valuation, this issue can be determined when addressing the degree of any economic obsolescence caused by rate regulation.

121. FERC and the RCA do not have jurisdiction to determine the proper value of TAPS for state ad valorem tax purposes. Their valuations of TAPS for purposes of establishing a tariff do not inform this Court as to the value of TAPS for ad valorem tax purposes under AS 43.56.060(e)(2).[179]

122. In 2007, SARB addressed the Owners' assertion that the assessed value of TAPS cannot exceed the value of its regulated tariff income stream.[180] The Board found that "[a] regulated tariff does not produce an income that would capture the current economic value of the pipeline."[181] Further, SARB concluded that "uncertainty about future tariff rates makes any valuation based on the capitalization of future tariffs very unreliable."[182]

123. SARB correctly concluded that tariff income is not the appropriate determinant of the full and true value of TAPS in the applicable tax years.[183] Mr. Hoffbeck's observations

[179] *See Tenn. Gas Pipeline Co. v. Town of Hudson*, 766 A.2d 672, 675-76 (N.H. 2000) (holding that replacement cost method, not net book cost method, was the proper method for valuing the pipeline company's FERC-regulated property).

[180] MUN7-0234 at 13.

[181] MUN7-0234 at 13.

[182] MUN7-0234 at 13.

[183] *See* MUN7-0234 at 16; MUN7-0236 at 28 – 30.

on Mr. Mark's testimony that the bulk of the physical assets that are being valued in this case are no longer included in TAPS' rate base demonstrate that a tariff-based approach would fail to value all of TAPS.[184] Case law throughout the nation makes clear that, even under a market value standard, courts do not typically equate net book earnings with value for ad valorem tax purposes.[185]

124. As in the 2006 matter, this Court finds that Mr. Podwalny's description of TAPS as a non-investment property within each Owner's integrated system is consistent with the statute and best supports the Division's and SARB's determination with respect to the economic value of TAPS.[186] To the extent that there is a market for TAPS, it is the ANS producers (or an integrated refinery operation such as Koch). For the evidence persuasively demonstrates that ANS producers would rebuild TAPS at a cost of billions of dollars to transport ANS petroleum products to market if TAPS was not in existence as of the lien dates. And the producers would replace TAPS not for the tariff income they might realize, but to monetize the approximately 7 to 8 billion barrels of proven reserves that were at the ANS as of the lien dates.

---

[184] Tr. 1241-22 (Hoffbeck).

[185] *See Tennessee Gas Pipeline Co. v. Town of Hudson*, 766 A.2d 672, 675-676 (N.H. 2001); *Polk County v. Tenneco, Inc.*, 554 S.W.2d 918, 922-23 (Tex. 1977) (concluding that the net book value did not measure the market value for the entire pipeline's property); *Boston Edison Co. v. Board of Assessor of Watertown*, 439 N.E.2d 763, 766-67 (Mass. 1982) (net book cost of property does not set an upper limit on the property's value for location taxation); *Appeal of Public Serv. Co. of N.H.*, 471 A.2d 1182, 1185-86 (N.H. 1984) (rejecting the taxpayer's argument that evidence demanded a finding that net book value was an appropriate measure of market value for all of utility's property); *Public Service Co. of N.H. v. Town of Ashland*, 377 A.2d 124, 125-26 (N.H. 1977) (holding that even though net book value provides the "rate base" upon which plaintiff's rate of return is calculated, the value of the property for tax purposes and the value for rate making purposes need not be the same); *Public Services Co. v. New Hampton*, 136 A.2d 591, 597 (N.H. 1957) (holding that value of property for tax purposes and its value for rate making purposes need not be the same).

[186] Amended Decision ¶ 91.

125. For the reasons set out above, this Court finds that SARB's determinations for the three tax years at issue, which strived to determine the full and true value of TAPS based on the economic value of its continued use in transporting ANS proven reserves to market, has not been demonstrated to constitute a fundamentally wrong principle of valuation.[187]

V. THE OWNERS' MAINTENANCE OF TAPS' CAPACITY OF 1.1 MILLION BBL/D WITH UPWARD SCALABILITY TO 2.1 MILLION BBL/D

126. TAPS' current design capacity is 1.42 million bbl/d.[188] However, some of the original Legacy pumps have been taken out of service and new SR pumps are being installed at four pump stations. The current upgraded pumps are able to transport up to 1.1 million bbl/d on a yearly average with a maximum of 1.14 million bbl/d during winter months.[189] With additional modular pumps, TAPS' current physical capacity can be increased. For example, Mr. Falcone indicated that if two additional pump stations were added, TAPS could transport 1.5 million bbl/d.[190]

127. Although TAPS cannot immediately transport 2.1 million bbl/d, the evidence persuasively establishes that with sufficient lead time, TAPS as currently configured is able to transport any volume up to 2.1 million bbl/d, should the need arise, with the installation of additional pumps and use of DRA.

---

[187] Amended Decision ¶ 92.

[188] Tr. 7367 (Falcone); MUN7-0215 at 258.

[189] Tr. 7139-7143 (Ray).

[190] Tr. 2730 (Falcone).

128. DB-180 is an Alyeska document that evidences the design basis for TAPS. DB-180 indicates at four places that a throughput range for TAPS is 300,000 to 2.1 million bbl/d.[191] DB-180 also references the maximum or ultimate throughput of 2.1 million bbl/d in an additional four places in the document.[192] Thus, there are eight different places in DB-180 that specifically refer to a 2.1 million bbl/d standard as the maximum throughput of TAPS.

129. In accordance with the requirements of DB-180, the mainline pipe is currently maintained at a 2.1 million bbl/d throughput standard.[193] The evidence at trial persuasively demonstrates that neither the mainline 48-inch pipe nor any other part of TAPS is maintained based upon the current throughput or DOR forecasts for future production, but is instead maintained for considerably higher potential throughputs.[194]

130. Any proposed design change to DB-180 must be approved by the Joint Pipeline Office.[195] No evidence was introduced to demonstrate that DB-180's design criteria have been changed.[196] The Court finds that DB-180 continues to be the controlling document with regard to the design basis for TAPS, and that document sets forth 2.1 million bbl/d as the maximum throughput capacity.[197]

---

[191] Tr. 5055-5059 (Hisey); MUN7-9023 at 209, 217, 239, 262.

[192] Tr. 5055-5059 (Hisey); MUN7-9023 at 217, 262, 268, 343.

[193] Tr. 4957, 4970, 6444 (Hisey); MUN7-2069 at 262.

[194] Tr. 6445 (Hisey).

[195] Tr. 4983, 5053-54 (Hisey); MUN7-9023 at 37-38.

[196] Tr. 7061-62 (Ray).

[197] MUN7-9023 at 209, 217, 239, 262, 268, 343.

131. The evidence at trial demonstrated that the current mechanical capacity of TAPS is 760,000 bbl/d and that with DRA, TAPS is currently physically able to transport 1.1 million bbl/d.[198]

132. In the Amended Capacity Settlement Agreement ("ACSA"), "TAPS Capacity" is a defined term that represents the "Pipeline's capacity set forth on Exhibit C."[199] In turn, "Exhibit C" sets forth the "TAPS Capacity Table" that establishes 1.1 million bbl/d as the "TAPS Capacity" after January 1, 2004 until the Agreement expires at the end of 2011.[200] An Owner's right to transport its percentage ownership share is based upon "Actual Daily Pipeline Capacity" which, in turn, is based upon "TAPS Capacity" as defined in "Exhibit C."[201] Exhibit C indicates "All volumes are in barrels."[202] The associated TAPS' Operating Agreement specifies that a barrel is "42 U.S. standard gallons at 60° Fahrenheit."[203]

133. The ACSA discussed "flow improvement" allocation as:

> [T]he allocation among the Owners of flow improvement that exceeds TAPS Capacity, whether achieved through the use of a drag reducing agent or through other means; provided, however, that such flow improvement shall be exclusive of any Capacity Cushion and shall be allocated only to the extent that it exceeds TAPS Capacity . . . .[204]

The concepts of flow and "flow improvement" with respect to TAPS are concepts related to

---

[198] Tr. 7137-39 (Ray). This Court was unpersuaded by Mr. Ray's testimony that TAPS' current capacity is only 870,000 bbl/d because the Owners would need to spend approximately two million dollars to upgrade DRA injection sites before TAPS could carry 1.1 million bbl/d. *See* Tr. 7049-51 (Ray).

[199] MUN7-0215 at 213.

[200] MUN7-0215 at 225.

[201] MUN7-0215 at 213.

[202] MUN7-0215 at 225.

[203] TO-07-0179.0218.

[204] MUN7-0215 at 214-15.

the flow of oil[205] – which is related to physical capacity, not nominating capacity.

134. This Court finds that as between the Owners, a primary function of the ACSA was to resolve the nominating dispute among them. But the State was also a party to the agreement. Upon consideration of all the evidence, this Court is not persuaded by the Owners' assertion that the ACSA should be read to concern only a nomination process. A right to transport up to an ownership percent of 1.1 million bbl/d would have little meaning without the actual ability to transport those same barrels.

135. The Owners assert that the ACSA could only address nominating issues because FERC approved the ACSA pursuant to § 5(1) of the Interstate Commerce Act, and "Section 5(1) of the ICA applies to the ACSA only to the extent the ACSA provides for a 'pooling' arrangement that allocates pipeline capacity on a basis other than each TAPS Owner's percentage ownership share."[206] Yet the FERC order approving the ACSA does not expressly deem the agreement to constitute a pooling arrangement; rather, FERC stated it is approved "even if the Amended CSA is deemed to be a pool."[207]

136. The Owners' current reading of the ACSA is similar, if not identical, to the "mechanical capacity" position of certain of the Owners that was compromised away when all Owners reached agreement through the ACSA. The "mechanical capacity" position was that each Owner could only transport its ownership share of TAPS' current mechanical capacity.[208]

---

[205] Tr. 7080-81 (Ray).

[206] Owners' Proposed Findings of Fact and Conclusions of Law ¶ 631.

[207] TO-07-0190.0008. In the FERC order approving the ACSA, the Commission also stated, "We concluded that the [TAPS] Quality Bank agreement was no more a pool than the joint operation of TAPS itself. We believe that the same reasoning is applicable to the Amended CSA." TO-07-0190.0007.

[208] Tr. 7062-63 (Ray).

137. The conduct of the Owners after execution of the ACSA further demonstrates that the parties intended for TAPS to have a physical capacity of 1.1 million bbl/d (with 1.14 million bbl/d capacity for winter flow rates). As held by the Alaska Supreme Court, the parties' conduct after entering into a contract is probative of intent. Conduct is a better indicator of intent than is testimony.[209] The Owners used a design basis for the SR project from 300,000 to 1.14 million bbl/d with upward scalability to 2.1 million bbl/d.[210] The SR project is not yet complete, but the Owners plan to complete it.[211] The Court finds that the Owners would not continue to spend over $700 million on SR to provide a capacity to transport up to 1.14 million bbl/d with upward scalability to 2.1 million bbl/d if such capacity and upward scalability were neither required nor desirable. The Alaska Supreme Court has held that "evidence that both parties made substantial investments in the plant supports a conclusion they each intended to retain the items in which they invested[.]"[212]

138. Also instructive to this Court were the Owners' representations to the RCA when seeking to abandon pump stations as part of their SR efforts. In that process, the Owners made a verified representation to the RCA:

> After completion of [Strategic Reconfiguration], TAPS will be able to transport up to 1.14 million barrels per day. Moreover, should there be any additional oil fields brought on line that would cause throughput to exceed the 1.14 million barrels per day figure, the design of the remaining TAPS pump stations will be modular and

[209] *North Pac. Processors, Inc. v. City and Borough of Yakutat,* 113 P 3d 575, 585 (Alaska 2005). *See also Peterson v. Wirum*, 625 P2d. 866, 870 (Alaska 1981) (conduct during performance can be admissible extrinsic evidence but opinions expressed during litigation regarding parties' intent do not establish an issue of fact regarding the parties' reasonable expectations at the time they entered into the contract).

[210] Tr. 9198-99 (Malvick).

[211] Tr. 7140 (Ray).

[212] *North Pac. Processors*, 112 P.3d at 585 (citations omitted).

will allow current and increased throughput capability within 36 months by the addition of modular units[.][213]

139. AS 42.06.290(a) states that "[a] pipeline carrier may not abandon or permanently discontinue use of all or any portion of a pipeline or abandon or discontinue any service rendered by means of a pipeline . . . without the permission and approval of the commission[.]" Such approval may only occur "after due notice and hearing, and a finding by the commission that continued service is not required by public convenience and necessity."[214]

140. The RCA granted the Owners the right to abandon several pump stations based upon the representations of the Owners that they would maintain the capacity to transport 1.14 million bbl/d[215] and their representation "that should North Slope production ever exceed the 1.14 million barrels per day, the design of the remaining operating pump stations will allow for increased throughput capability within 36 months by adding modular units to those pump stations."[216] The RCA order also noted that the TAPS Owners had represented that the abandonment of those several pump stations "will not interfere with the TAPS' ability to accommodate current or future throughput requirements, and will have no impact on the stipulated capacity requirements under the Amended Capacity Settlement Agreement."[217] In a footnote, the RCA noted that the "TAPS carriers stated that the Amended Capacity Settlement Agreement provides a stipulated aggregate capacity of 1.1

---

[213] MUN7-0218 at 19, 22.

[214] AS 42.06.290(a).

[215] MUN7-0219 at 11. Although this exhibit was not admitted into evidence, the Court has taken judicial notice of this RCA Order P-04-21 dated April 6, 2005.

[216] MUN7-0219 at 11.

[217] MUN7-0219 at 12-13.

million barrels per day for the years 2004 forward."[218] The Court finds that the Owners' representations to the RCA are consistent with this Court's reading of DB-180 and the ACSA. In the 2010 Amended Decision, this Court interpreted the ACSA to require the Owners to maintain a physical capacity of 1.1 million bbl/d. This Court again finds that the weight of the evidence presented at the trial of the 2007 through 2009 tax years supports that contractual interpretation of the ACSA. During the lien years the Owners had a legal duty to maintain TAPS' physical capacity to transport up to 1.1 million bbl/d with upward scalability should new fields be developed.

VI. CHOICE OF VALUATION METHOD

141. All parties agree and every appraiser testified that in appraising a property, appraisers typically consider three generally recognized approaches to value: the cost approach, the income approach, and the comparable sales approach.[219] The cost approach is based upon a principle of substitution.[220] This principle provides that a prudent buyer will not pay more for an existing property than the cost of acquiring a substitute property of equivalent utility.[221] The principle of substitution assumes replaceability without undue delay.[222] Under the income approach, "value is indicated by a property's earning power, based on the capitalization of income."[223] Under the comparable sales approach, "value is indicated by recent sales of comparable properties in the market and other supporting

---

[218] MUN7-0219 at 13, n. 41.

[219] Tr. 11766, 11966 (Remsha); Tr. 11229, 11238-39 (Podwalny); 1020 (Connolly).

[220] Tr. 1153-54, 1157-58 (Hoffbeck).

[221] *The Appraisal of Real Estate* at 38-39.

[222] *The Appraisal of Real Estate* at 380.

[223] *The Appraisal of Real Estate* at 130.

transactional information."[224] All parties fully litigated the issue of whether the cost, income, and sales comparison approaches are reliable indicators of value for TAPS in the 2007, 2008, and 2009 trial de novo.

142. The applicable statute and regulation require an assessment that captures the "economic value" of TAPS within the context of the ANS proven reserves. TAPS' economic value derives from its use in providing primarily affiliated transportation and market access for an entire oil region. Since 2005 through the lien years at issue, SARB has repeatedly held that the cost approach best captures the full economic value of TAPS consistent with AS 43.56.060(e)(2).[225]

143. The unique nature of TAPS as a limited-market and special-purpose property supports SARB's use of the cost approach as the only reliable indicator of value.[226] TAPS was specifically designed, constructed, and adapted to its particular use – to move affiliated ANS crude oil from the North Slope to Valdez.[227] A property with this unique function is properly valued under the cost approach.

144. Owners' expert Roger Marks recognized that if the tariffs are zero, it would be appropriate to value TAPS using the cost approach.[228] Mr. Marks also acknowledged that the Owners would probably operate TAPS even if it had no tariff income.[229]

145. The cost approach is particularly reliable when a property is first built or when

---

[224] *The Appraisal of Real Estate* at 130.

[225] *See, e.g.* MUN7-0236 at 8-32.

[226] Tr. 11355-56 (Podwalny); Tr. 11903 (Remsha).

[227] Tr. 8196 (Cicchetti); MUN7-0001 at 3767 (Coulson Dep.).

[228] Tr. 7852-55 (Marks).

[229] Tr. 12170 (Marks).

it undergoes a substantial renovation.[230] At the time of the 2007, 2008, and 2009 valuations of TAPS, the $700 million SR project was underway to upgrade TAPS.[231]

146. The extensive cost studies presented by both the Municipalities and Owners further support reliance on the cost approach.

147. An income approach based solely upon tariff income is not reliable for valuing an integrated, special-purpose property that has been adapted to a specific use for which the income stream is not the economic driver or basis for the property's construction and continued use.[232]

148. In its 2009 Decision, SARB explained its rejection of the tariff-based income approach as follows:

> The fact that the TAPS produces a tariff income in addition to transporting oil would not justify reliance on an income approach, as opposed to the generally applied cost approach, because oil transportation, not the TAPS tariff income stream, is the motivation for ownership of the TAPS.[233]

149. The sales comparison approach is generally not reliable for valuing limited-market properties or special-purpose properties such as TAPS when there are no comparable sales, or when the sales that do exist are not comparable because the subject property has been adapted to a particular use at a particular location.[234]

---

[230] Tr. 11994 (Remsha).

[231] Tr. 7140 (Ray).

[232] Tr. 12348 (Connolly); Amended Decision ¶ 120.

[233] MUN7-0236 at 30.

[234] *Fed. Reserve Bank of Minneapolis v. State*, 313 N.W.2d 619, 622-624 (Minn. 1981); MUN7-0234 at 17 (2007 SARB); MUN7-0236 at 30 (2009 SARB); *Valuing Machinery and Equipment* at 6.

150. In addition, the sales comparison approach is not generally used for valuing properties that are integrated with other properties because each sale has to be substantially adjusted to reflect only the portion of the integrated enterprise being valued.[235]

151. The standard treatise for machinery and technical specialties ("MTS") states:

> The income approach to value is not widely used today by most MTS appraisers; the reasons given include the difficulty in determining income that can be directly related to a specific asset, the concern over the reliability of income forecasts, and the multitude of variables involved in this valuation approach. . . . The sales comparison approach is not feasible when the subject property is unique.[236]

152. Other courts have similarly held that regulated pipelines should not be valued for ad valorem purposes under either the income or comparable sales approach.[237]

153. The Division and SARB considered all three of the primary approaches to valuation before determining that the Replacement Cost New Less Depreciation ("RCNLD") approach was appropriate.[238] Based upon the evidence presented at the trial de novo, this Court finds that reliance on the cost approach is appropriate to determine the "full and true" value of TAPS for 2007, 2008, and 2009.

\\

\\

\\

\\

---

[235] TO-07-0004.0087 (American Appraisal). In the case of TAPS, every sale of an interest in TAPS has been part of a larger integrated transaction.

[236] *Valuing Machinery and Equipment* at 122, 159-60.

[237] *Transcontinental Gas Pipeline Corp.*, 545 A.2d at 746; *Tenneco*, 104 A.D.2d at 514; *Matter of Onondaga County Water Dist. v. Bd. of Assessors of Town of Minetto*, 350 N.E.2d 390, 392 (N.Y. 1976); *Tex E. Transmission Corp. v. E. Amwell Twp.*, 13 N.J. Tax 24, 28-29 (N.J. Tax Ct. 1992); Amended Decision ¶ 12.

[238] MUN7-0234 at 2, 13, 16-17; MUN7-0235 at 2, 15-16; MUN7-0236 at 2, 27-32.

VII. THE COST APPROACH

154. There are three starting points for the application of the cost approach: original cost, reproduction cost, or replacement cost.[239] The use of original cost, either in nominal dollars or indexed to current dollars, is a limited but useful indicator of the cost to build TAPS today. TAPS cost approximately $8 billion to build in 1977 dollars – an amount that the Division calculated as equal to $23.4 billion for 2009 based upon trending the original cost using Marshall & Swift.[240] SARB noted the $19.8 billion Pro Plus RCN compared favorably to the original trended cost for that lien year.[241]

155. Reliance on a trended original cost as the basis for valuing TAPS is not warranted because TAPS' original design has been substantially updated and a trended original cost would not capture the value of the asset in place as of the lien dates.

156. A reproduction cost is the cost to replicate an exact duplicate or replica of what is in place, which could include substantial obsolescence.[242]

157. A replacement cost analysis replaces TAPS' current equivalent utility based on modern design, materials, and construction techniques.[243] The Owners and the Municipalities both presented replacement cost new ("RCN") estimates to the Board and to this Court in the de novo trial, although as discussed herein the Municipalities' RCN was far more similar to the existing TAPS than the RCN presented by the Owners.

---

[239] *The Appraisal of Real Estate* at 378.

[240] MUN7-0236 at 31 n. 10 (SARB 2009 Decision).

[241] MUN7-0236 at 31 n. 10 (SARB 2009 Decision).

[242] *The Appraisal of Real Estate* at 385.

[243] *The Appraisal of Real Estate* at 385-86; Tr. 580 (Remsha).

A. Replacement Cost New

158. RCN is "the current cost of a similar new property having the nearest equivalent utility as the property being appraised, as of a specific date."[244] It has also been defined as "the estimated cost to construct, as of the effective date, a substitute for the [property] being appraised using contemporary materials, standards, design, and layout."[245]

159. In an *Appraisal Journal* article titled *Replacement of What?* that was relied upon by Mr. Hoffbeck at trial, Donald Treadwell opined that:

> The selection of an appropriate replacement model in the cost approach is critical to the appraisal. The use of a replacement model that is significantly different from the subject may challenge implicit assumptions concerning the extent of functional and economic obsolescence incurred by components of the subject.[246]

160. RCN estimates fall along a continuum from a complete redesign to a near reproduction.[247] This Court finds that the concerns raised in the Treadwell article and discussed by Mr. Hoffbeck in the context of the historical examples of redesign persuasively demonstrate why it is important to use the correct replacement property and then adjust the RCN using the tools set out in the appraisal literature such as functional and economic obsolescence adjustments to arrive at the value of the subject property.

161. This Court finds that the evidence does not support the Assessor's apparent assertion that at least some components of the Pro Plus estimate may be reproduction estimates. Rather, the Pro Plus estimate replaced the utility of TAPS, but utilized modern and current design, materials and construction techniques in its design, work plan, and

---

[244] *Valuing Machinery and Equipment* at 186; Tr. 580 (Remsha).

[245] *The Appraisal of Real Estate* at 385.

[246] MUN7-0046 at 25; Tr. 1056 (Hoffbeck).

[247] Tr. 12773 (Greeley).

estimate. And, as further discussed herein, the Assessor's placement of the Stantec design as somewhere in the middle of the continuum between a redesign and a reproduction is not supported by the evidence.

1. A Summary of the Cost Studies

162. In 2007, SARB relied on Mustang Engineering's 2006 RCN trended forward one year, which estimated a replacement cost of $8,276,423,150.[248] At the de novo trial, no party supported the Mustang cost study.

163. Before SARB in 2007, the Owners also presented evidence on a 30-inch pipeline study prepared by Mustang.[249] The conceptual design basis assumptions included: 850,000 bbl/d maximum flow with the use of DRA, X-100 pipe, and seven pump stations.[250] SARB did not rely upon this 30-inch pipeline study in its 2007 decision.[251]

164. In 2008, the Municipalities first presented the Pro Plus study to SARB.[252] The Department and the Board relied upon the Pro Plus RCN cost estimate of $17.02 billion.[253] For that year, Pro Plus adjusted the original cost of the VMT for superadequacy, inflation-trended the revised cost, and accepted Mustang's numbers for several items that they had insufficient information to independently estimate.[254] The estimate was made before any significant discovery had been obtained by the Municipalities.

---

[248] MUN7-0234 at 12.

[249] 2007 R. 13059-84.

[250] 2007 R. 13059-84.

[251] 2007 R. 584-98 (MUN7-0234 at 11-24).

[252] MUN7-0235 at 15.

[253] 2008 R. 11515-11825.

[254] MUN7-0235 at 15.

165. By 2009, Pro Plus had received new information from discovery in the 2006 de novo tax case and had added the expertise of an engineering firm specializing in marine terminals. Before SARB, Pro Plus estimated the RCN of the entire system, including the VMT, at $21.1 billion in 2009.[255] After some adjustment, SARB found that the RCN was $19.805 billion.[256]

166. Also before the Board in 2009 was a hydraulic analysis conducted by Mustang Engineering on behalf of the Owners.[257] The hydraulic analysis assumed a 42-inch pipeline from Prudhoe Bay to Valdez at "the current flow rate of 1 million bbl/d."[258] Mustang concluded that "[t]o obtain a flow rate of 1 MMBOPD [million bbl/d], the 42-inch system requires a full complement of 12 pump stations. There is virtually no capacity over 1 million bbl/d in the 42-inch pipeline."[259] Mustang also conducted a cost analysis between the 42-inch and 48-inch line and concluded that

> [w]hen comparing the base 48" system with a potential 42" system, the 42" system would require an approximate increase in investment, due to the higher horsepower requirements, of $275MM and an approximate decrease due to saving pipe material and installation costs of $150MM. The net investment cost difference is an increase of $125MM for installation of a 42" line versus a 48" line. This rough estimate does not include the additional operating costs for 12 pump stations, as opposed to 6, or spare parts costs (included in the program management fees).[260]

---

[255] 2009 R. 16-67.

[256] MUN7-0236 at 18.

[257] 2009 R. 10341-46; Tr. 6870-71 (Greeley).

[258] 2009 R. 10343.

[259] 2009 R. 10345.

[260] 2009 R. 10345.

167. In evaluating the Stantec 30-inch pipeline, this Court has accorded some weight to the opinion of the Owners' experts in 2009 before SARB that a 42-inch pipeline was inadequate to transport throughput of over 1 million bbl/d.

168. The Owners first presented the Stantec cost study to SARB in 2010. The Owners presented a similar Stantec cost study to SARB in 2011.

169. In both 2010 and 2011, SARB held that reliance on the Stantec 30-inch pipeline for valuing TAPS "would have been improper" because "costing a hypothetical property that is so different from the existing property, to measure obsolescence, is an extreme and inappropriate use of this appraisal technique."[261]

170. In its Amended Decision, this Court relied upon the Pro Plus RCN and found that as of January 1, 2006, a replacement pipeline with utility equivalent to TAPS would cost approximately $18 billion to replace.[262]

171. At the trial de novo before this Court for the current tax years, the Municipalities presented the Pro Plus cost studies which estimated the cost to replace TAPS' equivalent utility in 2007 at $19.606 billion, in 2008 at $21.471 billion, and in 2009 at $21.263 billion.[263] The Owners presented the Stantec cost studies estimating the cost to replace TAPS with a 30-inch pipeline at $9.352 billion in 2007, $9.702 billion in 2008, and $9.721 billion in 2009.[264]

---

[261] *See* MUN7-0238 at 30-31.

[262] Amended Decision ¶ 511.

[263] Tr. 3787 (Ellwood); MUN7-0008 at 1627-1628.

[264] TO-07-0021 at 8; TO-07-0023 at 8; TO-07-0025 at 8. The Stantec figures do not include interest during construction and ad valorem taxes, which were computed by American Appraisal.

172. Pro Plus used a design criteria of 1.1 million bbl/d maximum throughput for all three lien years with a 48-inch diameter pipe size.[265]

173. Stantec used a 30-inch pipeline with a design basis of 900,000 bbl/d for 2007, 800,000 bbl/d for 2008, and 750,000 bbl/d for 2009.[266]

174. The following chart compares some of the design parameters of the existing TAPS, the Pro Plus RCN, and the Stantec RCN:

	TAPS	Pro Plus RCN	Stantec RCN
Diameter:	48"	48"	30"
Maximum Capacity of Mainline Pipe:	2.1 million bbl/d	2.1 million bbl/d	Unknown – no more than 1.1 million bbl/d
Maximum Pressure:	1,180 psi	1,180 psi	2,158 psi
Velocity at 1.1 million bbl/d:	10 ft/s	10 ft/s	15 ft/s
Number of Miles Aboveground:	420	420	629
Vertical Support Members:	Dual-pile	Dual-pile	Mono-pile
Thermosyphons:	Inside VSMs	Inside VSMs	Freestanding
Aboveground Pipe Support Spacing:	60 ft.	60 ft.	90 ft.

[265] Tr. 3716 (Ellwood); Tr. 4460 (Steindorff).

[266] Tr. 4472 (Steindorff); TO-07–00021 at 7; TO-07–00023 at 7; TO-07-00025 at 7.

2. The Stantec Hypothetical Pipeline Is Not an Acceptable Comparison Property to TAPS for Ad Valorem Tax Purposes

175. The parties extensively litigated whether this Court should adopt the Stantec 30-inch pipeline or the Pro Plus 48-inch pipeline as the basis for the RCN calculation for the 2007, 2008, and 2009 tax years. The Municipalities presented evidence and argued that the Stantec 30-inch pipeline is too different from the existing TAPS such that it cannot provide a reasonable basis for determining the full and true value of TAPS. They further argued that the Stantec 30-inch pipeline is premised on an inappropriate appraisal technique and as a practical matter, it will not be able to operate within reasonable design parameters.

176. The Owners presented extensive engineering testimony in support of the Stantec RCN. They also rely on Mr. Hisey and Mr. Greeley's testimony to support their 30-inch pipeline design. Mr. Hisey testified that a 48-inch pipeline would likely not be the optimal design for a new pipeline if TAPS' throughput was projected not to exceed 900,000 or 700,000 bbl/d. But Mr. Hisey also testified that the optimal size for a pipeline that would be similar to and have the same utility as the existing TAPS would be a 48-inch pipeline. In that regard, he stated "the 30-inch design would not be the right design for any of the operating years . . . in question, 2007, 2008, and 2009 . . . I cannot assess how you call it a similar design to the existing facility; no, it's not similar at all."[267]

177. Although it appeared that the Assessor Mr. Greeley testified that he would choose the Stantec RCN over the Pro Plus RCN, the Department's counsel stated in closing that Mr. Greeley was not choosing between the two cost studies.[268] Regardless, this Court

[267] Tr. 5052, 6457-58 (Hisey).

[268] Tr. 6809 (Greeley); 8461 (Johnson).

gives little weight to Mr. Greeley's testimony regarding the Stantec cost study since he demonstrated a lack of knowledge about key components of that study.[269]

178. None of the approximately twenty experts testifying in the RCN section of this case could identify a single crude oil pipeline that had been built with each of the characteristics of Stantec's 30-inch pipeline design.

179. Mr. Hoffbeck identified certain criteria to determine whether a proposed replacement property should be used as the starting point in a cost approach, which this Court has found helpful to consider:

a. whether there are legal restrictions that would make the proposed property unacceptable, and if so whether there is a likelihood they can be removed;

b. whether the proposed replacement property is of similar quality and like utility to the subject property;

c. whether the replacement property is an appropriate application of appraisal theory for use in the assessment process;

d. whether the design will operate as specified;

e. whether the design captures all direct and indirect costs associated with the construction of the replacement property, and if not, whether the estimate can be adjusted to reflect all of those costs; and

f. whether the replacement property is similar enough to the subject property to permit the accurate identification and quantification of obsolescence.[270]

---

[269] For example, Mr. Greeley was unable to answer questions regarding the amount of horsepower required for the pumps in Stantec's cost study, or whether all three trains of pumps need to be running at 1.1 million bbl/d. Tr. 6962-6970 (Greeley). In addition, Mr. Greeley testified that he "looked at the equipment rates that were used for the construction of the Valdez Marine Terminal;" however, Stantec did not determine equipment rates, but rather its equipment costs are based on a percentage of direct labor. *Compare* Tr. 13000-13003 (Greeley) *with* Tr. 2496-97 (Rein).

[270] Tr. 11523-11554 (Hoffbeck).

a. Legal Restrictions

180. The TAPS Owners have commited to the RCA to maintain and expand TAPS' existing capacity if needed in the future. The Stantec design is inconsistent with these commitments and resultant RCA order and would require RCA approval.[271] This Court finds such approval improbable. The RCA would have to determine that the abandonment of TAPS' current 1.1 million bbl/d capacity and its upward scalability above that throughput is in the public interest – a finding likely to be challenged by existing and future stakeholders seeking to expand and optimize Alaska North Slope development.[272]

181. The Stantec RCN pipeline also does not meet the design specifications for the existing property as found in Alyeska's DB-180.[273] The DB-180 under the Design Criteria Section 4.3.2 specifies that:

> TAPS is designed to transport crude oil from Prudhoe Bay to Valdez, Alaska. Throughput range for the system is .3 to 2.1 MMSBPD [million bbl/d] under steady conditions of operations, although it should be noted that this may require installation of short term DRA injection facilities at various locations to reach the high end of this range.[274]

The General Hydraulic Criteria and Considerations Section of DB-180 states:

> [t]he mainline and facilities of the trans-Alaska pipeline system shall be designed to transport crude oil or other hydrocarbons from Prudhoe Bay, Alaska at nominal rates to Valdez, Alaska between 0.3 to 2.1 MMSBPD [million bbl/d]. Hydraulic design criteria shall apply to the mainline, mainline facilities, and connection facilities throughout this range of design mainline unless otherwise specified.[275]

---

[271] AS 42.06.290(a).

[272] Tr. 11526 (Hoffbeck).

[273] Tr. 4466 (Steindoff); Tr. 5170 (Riordan); Tr. 3391-92 (Annett).

[274] MUN7-9023 at 209; Tr. 4956, 4985, 4989-90, 5055-56, 6445 (Hisey).

[275] MUN7-9023 at 217; Tr. 5056-19 (Hisey).

DB-180 also states that, "[t]he mainline pumps at the designated pump stations are required to pump from 0.3 to 2.1 MMSBPD [million bbl/d]."[276] The piping systems are also "maintained to sustain maximum operating conditions up to 2.1 million barrels per day under all operating conditions allowed per *49 CFR 195, Transportation: Transportation of Hazardous Liquids by Pipeline*."[277] Although TAPS cannot currently transport 2.1 million bbl/d, if the pump stations that have been ramped down are brought back on line and DRA injection sites upgraded, then TAPS can transport 2.1 million bbl/d.

182. While Mr. Riordan of Alyeska suggested that DB-180 could be unilaterally changed by the Owners without following the formal process outlined in the DB-180, the evidence at trial persuaded the Court otherwise.[278] The DB-180 clearly provides that the Joint Pipeline Office ("JPO") must approve any change or variance of the TAPS design basis criteria set forth in DB-180.[279] And while Mr. Hisey, former Chief Operating Officer for Alyeska, acknowledges that editorial changes, such as naming buildings, are made to the DB-180 without regulatory approval, he could not recall any specific change to the DB-180 related to capacity or throughput that was made without regulatory approval.[280]

183. Further, as discussed above, this Court has again concluded that the Amended Capacity Settlement Agreement required the TAPS Owners to maintain at least 1.1 million bbl/d capacity during the lien years.

---

[276] MUN7-9023 at 239; Tr. 4989-4990, 5057 (Hisey).

[277] MUN7-9023 at 352; Tr. 5058 (Hisey).

[278] Tr. 5173-5174 (Riordan); Tr. 6448-49 (Hisey); Tr. 3392 (Annett); MUN7-9023 at 37.

[279] Tr. 5173 (Riordan); Tr. 4956, 4988, 5053-55, 5059, 6448-49 (Hisey). *See also* MUN7-9023 at 35, 37; Tr. 3392 (Annett) (discussing DB-180).

[280] Tr. 4988-89 (Hisey).

184. The Owners failed to establish by a preponderance of the evidence that the existing RCA requirements and the DB-180 design basis would permit the Stantec 30-inch pipeline to be built as a replacement for TAPS.[281]

b. The Stantec Design Is Not of Similar Quality and Like Utility

185. A replacement property should be "a similar new property having the nearest equivalent utility as the property being appraised."[282]

186. Utility in the appraisal context is not necessarily limited to how the property is currently being used.[283] The Owners' lead appraiser, Mr. Remsha, acknowledged that a 30-inch pipeline and 48-inch pipeline have "quite different utility from each other."[284] "By definition, utility is any aspect of the property that would create a desire for ownership. It's significantly different from the concept of usefulness, which is how it is currently being used."[285] Mr. Hoffbeck persuasively testified that TAPS' utility is more than its ability to ship oil at the current throughput levels[286] – it also includes TAPS' flexibility and upward scalability.

187. TAPS is 48 inches in diameter; the Stantec RCN is 30 inches. Mr. Remsha indicated that he has never before used a different diameter replacement pipe than the subject property for an RCN.[287]

---

[281] Tr. 822 (Podwalny).

[282] *Valuing Machinery and Equipment* at 44.

[283] Tr. 1060 (Hoffbeck).

[284] Tr. 12502 (Remsha).

[285] Tr. 1061 (Hoffbeck).

[286] Tr. 11532 (Hoffbeck).

[287] Tr. 579, 12506 (Remsha).

188. Mr. Remsha acknowledges that the design capacity for TAPS as of the lien dates was 1.42 million bbl/d.[288] Yet American Appraisal based their RCN on a pipe that could not meet that design capacity of TAPS, no matter how much DRA is used.[289]

189. At Stantec's 1.1 million bbl/d case, the 30-inch pipeline will be operating over 15 feet per second ("ft/s").[290] For Stantec's 2007 case, the velocity will be 12.7 ft/s; for the 2008 case, the velocity will be 11.3 ft/s; and for the 2009 case, the velocity will be 10.6 ft/s.[291]

190. The current TAPS, as well as the Pro Plus RCN, will operate at velocities of less than 10 ft/s for throughputs of up to 1.1 million bbl/d.[292] In defending the high velocities in their design, Alyeska engineer Joe Riordan testified that TAPS' velocities "approach[ed] 12 feet per second" when throughput was at its very highest at 2.136 million bbl/d.[293] However, TAPS was built with robust engineering to transport 2.1 million bbl/d at high velocities for temporary periods of time. In contrast, the Stantec design is built only to the minimum specifications necessary to transport the throughput for each of the lien years at issue. Moreover, at 2007 throughputs and at 1.1 million bbl/d, the Stantec RCN is designed to operate at velocities well above the maximum ever attained on TAPS' 48-inch mainline pipe.

---

[288] Tr. 534, 12506-07 (Remsha).

[289] Tr. 2086 (Pietsch).

[290] Tr. 4489 (Steindorff) (relying on MUN7-1182).

[291] Tr. 4489, 4504-07 (Steindorff) (relying on MUN7-1182).

[292] Tr. 4489, 4506-07 (Steindorff).

[293] Tr. 1594 (Riordan).

191. In comparing existing and planned pipelines ranging from 30 inches to 42 inches in diameter, the highest velocity is 7 ft/s.[294] The evidence persuasively demonstrates that the high velocities in Stantec's RCN exceed industry standards for crude oil pipelines and may cause surge pressure issues.[295]

192. TAPS was constructed and is operated at typical pressures for North American pipelines. DB-180 requires that the TAPS' internal design pressure be between 700 psi and 1180 psi, depending on the grade of pipe.[296] Similarly, Pro Plus's design operates at 1,180 psi.[297]

193. The Stantec 30-inch pipeline operates at far higher pressures than TAPS or a typical long-distance crude oil pipeline.[298] Stantec's design operates at 2,158 psi – approximately twice the pressure of the existing TAPS.[299]

194. There is no evidence in the record of a long-distance crude oil pipeline operating at such high pressures in North America.[300]

---

294 Tr. 4489 (Steindorff) (relying on MUN7-1182).

295 Tr. 4489-90, 4504-07 (Steindorff) (relying on MUN7-1182). DB-180 requires that the surge pressure rises do not exceed the internal design pressure by more than 10%. MUN7-9023 at 156.

296 MUN7-9023 at 156, 174.

297 Tr. 4469 (Steindorff).

298 Tr. 3802-03 (Ellwood); Tr. 2032-34 (Pietsch); Tr. 2971-73 (Ziehr); Tr. 5152 (Riordan); Tr. 4469-70 (Steindorff); Tr. 4953-54 (Hisey); MUN7-0009 at 4-5; MUN7-0029.

299 Tr. 4469 (Steindorff).

300 Tr. 2035-36 (Pietsch) ("Q. Has any 30-inch high pressure crude oil pipeline ever been demonstrated to operate in the world? A. At what we designed the pressure? No."); Tr. 2032-34: 18 (Pietsch) ("Q. Are you aware of any cross-country crude oil pipeline that operate at over 2000 psi? A. No"; "Q. Are you aware of any long-distance cross-country crude oil pipeline that operates at 1500 psi? A. I'd say no"); Tr. 2972 (Ziehr) ("Q. In fact, you are not aware of any pipeline in the world that's a cross-country crude oil pipeline that operates 1400 psi, correct? A. Personally not aware of it, correct"); Tr. 2971 (Ziehr) (acknowledging that his company had never built a cross-country crude oil pipeline anywhere that operated above 1480 psi); Tr. 5152 (Riordan) ("Q. Have you ever done a project—a cross country pipeline project at these kinds of pressures in the past? A. No, sir"); Tr. 3116-17 (Meyer) ("Q. Are you aware of any ... long-distance crude oil pipeline in the world that operates above 1480? ... A. I am not.").

195. Through cross-examination of a Pro Plus expert, the Owners referred to one example of a high-pressured crude oil pipeline, the 30-inch Endymion. However, the Endymion is a 90-mile subsea pipeline that has an entirely different design related to the external water pressure on the underwater pipe.[301] This Court does not find this subsea pipeline to be similar to TAPS.

196. The operation of a pipeline at higher operating pressures is not as operationally or environmentally safe as the operation of a pipeline at lower operating pressures.[302] Operation at higher pressure also requires greater horsepower and has less of a safety margin than operation at lower pressures.[303]

197. The Stantec design does not have equivalent utility to TAPS with respect to operating pressure.

198. At any given throughput level a 30-inch pipeline will require more horsepower than a 48-inch pipeline due to frictional loss.[304] For example, at a flow rate of 800,000 bbl/d, the 30-inch pipeline requires approximately 110,000 horsepower while the 48-inch pipeline requires approximately 58,000 horsepower.[305]

199. The Stantec 30-inch pipeline would require more DRA than a 48-inch pipe at any given throughput.[306] Very large amounts of DRA are necessary to attempt to reach 1.1 million bbl/d throughput.[307] This is substantially different from the existing TAPS.

[301] Tr. 3941-42 (Ellwood). Mr. Riordan acknowledged that the Endymion is not a cross-country pipeline. Tr. 5155 (Riordan).

[302] Tr. 4960-62 (Hisey).

[303] Tr. 4958-59 (Hisey).

[304] Tr. 5063 (Hisey); Tr. 3799-3800 (Ellwood); Tr. 4472-82 (Steindorff); Tr. 8123-28 (Modisette).

[305] Tr. 4472-75 (Steindorff); MUN7-0008 at 24.

[306] Tr. 5063 (Hisey).

200. The aboveground portions of TAPS' mainline pipe are supported on dual-pile vertical support members ("VSMs") with thermosyphons integrated into the design to maintain the appropriate ground temperature. VSMs are a unique method for supporting aboveground pipe in areas where there is concern that the warm crude oil pipeline would thaw the permafrost, causing settlement that may result in loss of support for the pipeline.[308] Thermosyphons help maintain the tundra in a frozen state as necessary. The aboveground VSMs on TAPS are in a zig-zag pattern to accommodate pipe expansion and contraction, as well as seismic activity which they have successfully withstood.

201. Unlike TAPS, the aboveground portion of Stantec's 30-inch line is supported almost entirely by single or mono-pile VSMs.[309] While there are mono-pile VSMs on the Alaska North Slope and at Valdez, the evidence persuasively demonstrates that mono-pile VSMs have never been proven to support long-distance crude oil transmission pipelines or pipelines in warm permafrost zones.[310]

202. The mono-pile VSMs that have found limited use have not been integrated with thermosyphons to maintain ground temperatures.[311] One of the Owners' experts, Mr. Carson, testified that he is unaware of the use of thermosyphons with mono-pile supports

---

[307] MUN7-1553.

[308] MUN7-0008 at 15.

[309] TO-07-0021 at 10.

[310] Tr. 3115 (Meyer) ("Q. Are you familiar with any cross-country crude oil pipelines built on monopiles that ... has not been built into frozen ground. A. On monopiles, no, I am not. Q. Anywhere in the world today? A. I am not"); Tr. 4466 (Steindorff) ("The unproven technology and the application thereof is in the form of the mono-piles and the thermosyphons. We know of no long-distance, cross-country pipeline of any size that's on mono-piles. I don't think anybody's given us an example yet"); Tr. 4483-84 (Steindorff); Tr. 4973-74 (Hisey) (Stantec's mono-pile design has not been tested with the size of line and conditions that would be required for the 800 mile pipeline from Pump Station 1 to Valdez, unlike the original TAPS' VSM design which was subject to full scale testing for an extended period of time, to ensure adequate lateral support, so that if the pipeline moves, it will not affect the loading on the VSM"); Tr. 6454-66 (Hisey).

[311] Tr. 3803-05, 3816-18 (Ellwood); Tr. 3202-03 (Carson).

anywhere in the world.[312] He testified that he would do full scale testing of the technology for at least a season or two in the field before relying on it for a project like the replacement of TAPS.[313] Likewise, Mr. Ellwood testified that he knows thermosyphons work and he knows mono-piles work, but he has never seen this combination supporting a major oil pipeline in a warm permafrost region.[314] In addition, pipeline operations could be impacted because there is no mechanical protection for the freestanding thermosyphons in the Stantec RCN.[315]

203. The thermosyphon study used in the Stantec replacement estimate was prepared by John Zarling, who was not a witness at trial.[316] Dr. Zarling's files were not provided to opposing counsel in discovery, nor had they been provided to the trial witnesses sponsoring the Stantec thermosyphons, Dr. Meyer and Mr. Carson of Michael Baker.[317] Thus, Mr. Carson could not tell the Court whether Dr. Zarling's analysis was correct,[318] and the Owners did not persuasively establish that the thermosyphon approach proposed for the Stantec 30-inch pipeline study is reliable.[319]

204. This Court finds that Michael Baker's mono-pile VSM design at 90-foot spacing does not provide the same level of pipe support and redundancy as the existing dual-pile

---

[312] Tr. 3210 (Carson).

[313] Tr. 3212 (Carson). *See also* Tr. 4973-75 (Hisey); Tr. 4466-68, 6614 (Steindorff).

[314] Tr. 3804, 6649-52 (Ellwood).

[315] Tr. 3819-20 (Ellwood).

[316] Tr. 3200-02 (Carson); Tr. 3112-23 (Meyer).

[317] Tr. 3200-01 (Carson).

[318] Tr. 3209 (Carson).

[319] Tr. 3200-3202 (Carson).

supports at 60-foot spacing on TAPS.[320] Evidence was presented that the smaller the diameter of the pipe, the closer the necessary spacing becomes.[321] And yet Stantec has proposed to increase the spacing from 60 feet to 90 feet for its 30-inch pipeline. The Owners' experts, Dr. Meyer and Mr. Carson, testified that if two adjacent supports failed, the Stantec pipeline would touch the ground.[322] Dr. Meyer acknowledged that the existing TAPS design requires that the pipe remains suspended in the event of two adjoining VSM failures.[323]

205. The Stantec pipeline design work by Michael Baker also deviates from DB-180 for geometry changes, wind loading, and temperature differentials.[324]

206. Over two hundred more miles of the Stantec 30-inch pipeline are aboveground and supported by VSMs than on the current TAPS.[325] The evidence persuasively showed that there are more safety risks and reliability issues for an aboveground pipeline.[326]

207. The decision to build the majority of the pipeline aboveground was not made by the Owners' structural engineer experts (Dr. Meyer and Mr. Carson) who were hired to design the VSMs, but rather by the Owners' hydraulics expert, Mr. Pietsch.[327] Dr. Meyer and Mr. Carson were told that the majority of the pipeline needed to be built aboveground so as to aid Mr. Pietsch's hydraulics and heat transfer.[328]

---

[320] Tr. 4466, 4484 (Steindorff); Tr. 3128 (Meyer).

[321] Tr. 4484, 4487-88 (Steindorff) (discussing MUN7-1167 at 2).

[322] Tr. 3129 (Meyer); Tr. 3204 (Carson).

[323] Tr. 3128 (Meyer).

[324] Tr. 3121-22, 3123, 3125-26 (Meyer). *Compare* TO-07-0013 at 17 *with* MUN7-9023 at 173-174.

[325] Tr. 3198 (Carson); TO-07-0021 at 10 (stating "[m]ajor portions (approximately 629 miles) of the pipeline are constructed aboveground using Vertical Support Members (VSM)"). *Cf.* MUN7-0001 at 490.

[326] Tr. 3801 (Ellwood).

[327] Tr. 3118 (Meyer).

208. Michael Baker's report "Aboveground Pipeline Verification" provides several pipe configurations, including 90-degree bends. These bends are needed in the Stantec design to take up the growth/shrinkage of the pipeline as it expands and contracts with changes in temperature.[329]

209. Mr. Pietsch indicated that he did not account for the 90-degree bends in his simulations and acknowledged that the use of 90-degree bends would affect the simulation results since every bend carries a pressure drop in the oil.[330]

210. For the foregoing reasons, this Court finds that the Stantec pipeline, including the mono-pile VSMs and thermosyphon design, is of lower or lesser quality than the current design on TAPS.

211. A work pad is an area built up with additional fill and stabilized to provide a site on which to perform work.[331] Pro Plus and Stantec disagree on whether gravel or ice should be utilized for the work pad on that portion of the right-of-way located north of the Brooks Range.[332]

212. Use of ice pads could complicate the construction of a new pipeline, as it would eliminate the ability to perform any construction during a significant portion of the year where neither ice nor snow would be available to construct roads or pads.[333]

---

[328] Tr. 3118-19 (Meyer). Mr. Rein, the primary witness on the Stantec RCN, testified that he was unaware that Mr. Pietsch had decided the percentage of the Stantec pipeline that would be aboveground. Tr. 5304 (Rein).

[329] TO-07-013 at 12-14.

[330] Tr. 2030-32 (Pietsch); Tr. 6668 (Ellwood).

[331] Tr. 3862 (Ellwood); MUN7-0008 at 7.

[332] *Compare* MUN7-0008 at 14 *with* TO-07-0021 at 21.

[333] Tr. 6484 (Tise).

213. The continuing utility of an ice pad is far less than the utility of a granular work pad. Alyeska has continued to maintain the gravel work pad for over 30 years for contingency purposes and for oil spill response. It is also useful to deploy personnel, heavy equipment, and materials for maintenance purposes.[334]

214. The fact that Stantec will not have a granular work pad adjacent to all of the 800-mile pipeline means that the Stantec RCN is of lesser utility than TAPS in this regard.

215. In the Keystone Canyon area, Michael Baker selected a different route for the Stantec RCN from the current route, placing the 30-inch pipeline along the highway. Although this new route could cause disruptions to the community and traffic and safety issues for the public during construction,[335] this Court finds that the Stantec proposed re-route would provide the same or similar utility as the current TAPS route.

216. Dr. Hite, an expert witness for the Municipalities, persuasively testified that large quantities of technically and economically recoverable oil exist in the Beaufort and Chukchi Seas, the Alaska National Wildlife Refuge, the National Petroleum Reserve Alaska, and the Central North Slope. Dr. Hite cited to a number of sources to support his testimony, including a federal evaluation and assessment of oil resources in Arctic Alaska that estimates there are potentially 30.85 billion barrels of economically recoverable oil available for shipment down TAPS.[336]

---

[334] Tr. 1243-45 (Baldridge).

[335] Tr. 5797 (Karlik); Tr. 3860-62 (Ellwood); Tr. 4165 (Tise); Tr. 4471-72 (Steindorff).

[336] Tr. 9613-26 (Hite); MUN7-001 at 4226.

217. Dr. Hite persuasively testified that if production within the National Petroleum Reserve-Alaska, the Chukchi Sea, and the Beaufort Sea were brought online, ANS production could total 1.5 million bbl/d.[337]

218. Although the potential recoverable oil reserves identified by Dr. Hite are not proven reserves, Dr. Hite's testimony is relevant in determining TAPS' utility and what constitutes an appropriate replacement property that is reflective of TAPS' utility. This is best reflected by the fact that the TAPS Owners are maintaining upward scalability of TAPS so as to be able to transport increased throughputs.

219. Stantec's pump station design is based on the assumption that the throughput rates during the lien years are the maximum throughputs.[338] The Owners' hydraulics expert Mr. Pietsch indicated that his 1.1 million bbl/d simulations for the Stantec RCN "were not the design plan rates. They were what I would call a maximum capacity test."[339] Mr. Pietsch added, "To me, maximum capacity is the highest...the system can flow at."[340]

220. Mr. Pietsch also performed a tank utilization study for the VMT, but testified that the maximum volume he used to determine tank utilization was 739,000 bbl/d.[341]

221. This Court finds that for the purposes of determining TAPS' value under the RCNLD method, a proposed replacement pipeline (before depreciation) must have an upward and downward flexibility to transport levels of throughput that is similar to the existing pipeline. Stantec's design significantly narrows the broad range of operating

---

[337] Tr. 9629-31(Hite).

[338] Tr. 5317 (Pietsch) (Stantec pipeline could not transport 2.1 million bbl/d; "It is designed for the throughputs that are used for each tax year.")

[339] Tr. 1957 (Pietsch).

[340] Tr. 1957 (Pietsch).

[341] Tr. 2123-25 (Pietsch).

capacities and conditions of the current TAPS, and thus does not have flexibility in throughput levels that is similar to the current TAPS.[342] It is not of similar quality and like utility to the existing TAPS.

c. Appraisal Theory

222. Under the cost approach, the goal is to estimate the cost of a new property with equal utility to the subject property, not a new plant with new utility.[343] When as a factual matter, the physical plant, the capacity, the operations, and the capabilities of a hypothetical plant are different from the subject property, it does not give sufficient guidance on how to value the existing subject property.[344] This is particularly true where the components of the subject property all contribute to the value of the property.

223. Other tribunals have found that a substitute property cannot be so dissimilar from the asset being valued that it does not represent a reasonable substitute. For example, in *American Crystal Sugar Company v. County of Polk,* the Minnesota Tax Regulation Division addressed whether it was proper appraisal practice under the cost approach to rely upon a cost study utilizing a hypothetical property with a substantially different design and capacity.[345] The taxpayer argued that if the property were replaced, the building would be vastly different, but its expert appraiser could not identify any current

[342] Tr. 6453-54 (Hisey); Tr. 8108-16 (Modisette).

[343] *The Appraisal of Real Estate* at 385; *Valuing Machinery and Equipment* at 44; Tr. 580 (Remsha); *American Crystal Sugar Co. v. County of Polk*, 2009 WL 2431376 at 21 (Minn. Tax Regular Div. 2009); *Fire Ins. Exch. v. Superior Court of Los Angeles*, 10 Cal. Rptr. 3d 617, 635 (Cal. App. 2d 2004); *Xerox Corp. v. Board of County Commissioners*, 87 P.3d 189, 192 (Colo. Ct. App. 2003) (holding that the cost approach is essentially an estimate of the cost of replacing the subject property with a new property that is equivalent in function and utility).

[344] *American Crystal Sugar Co. v. County of Polk*, 2009 WL 2431376 at 21 (Minn. Tax Regular Div. 2009).

[345] 2009 WL 2431376 at 18 (Minn. Tax Regular Div. 2009).

sugar beet plant that incorporated all of the modern design features that he proposed.[346]

The Minnesota tax division found that:

> As a factual matter, under the Petitioner's cost approach, the physical plant, the capacity, the operations and the capabilities of the hypothetical plant are completely different [than what exists]. While the hypothetical plant may be an ideal standard, it does not give us sufficient guidance in how to value [the existing property] as it stands.[347]

The tax division further explained:

> Under the cost approach we seek to value the building of a new plant with equal utility, not new utility. This would be like asking an appraiser to value a modest three bedroom house and getting back an appraisal on a ten bedroom mansion because that is what the owner would really want to build.[348]

Like the taxpayer in *American Crystal Sugar Company v. County of Polk,* the Owners' cost study is based on a hypothetical property that has very different capacity, operations, and capabilities than what currently exists on TAPS.

224. The Ohio Tax Board in *General Motors v. Cuyahoga County Board of Revision* reached a similar conclusion:

> Appellant has failed to demonstrate that its theoretical Greenfield model is, in fact, an "equal" substitute for this facility. Its characteristics vary substantially. It is much smaller. This, in our view, limits its flexibility for adaptation of other uses. It is less likely to be adaptable to shifts in future production requirements because of this limited size. Less space is available for storage or other ancillary needs. Its utility is not "equivalent."[349]

---

[346] 2009 WL 2431376 at 18 (Minn. Tax Regular Div. 2009).

[347] 2009 WL 2431376 at 19 (Minn. Tax Regular Div. 2009).

[348] 2009 WL 2431376 at 19 (Minn. Tax Regular Div. 2009).

[349] *General Motors v. Cuyahoga County Board of Revision,* 1995 WL 38387 *13 (Ohio Bd. Tx. App. 1995).

225. The Owners have referenced *Chevron U.S.A., Inc. v. City of Perth Amboy*[350] and assert that it is more on point than *American Crystal*. The Perth Amboy refinery was a fully integrated crude oil refinery until mid-1983 with a rated capacity of 168,000 bbl/d that processed a range of crude oils and produced a range of finished products.[351] After mid-1983, it became a 60,000 bbl/d refinery of heavy crude producing only one product: asphalt.[352] The New Jersey Tax Court held in 1988 that the property was correctly valued as an asphalt plant, as it could not return to full operations without a substantial investment – at a minimum, approximately $80 to $100 million.[353]

226. Unlike the Perth Amboy refinery, which had been an asphalt plant for five years at the time of the Tax Court's decision, TAPS' capacity and utility are unchanged – it is not currently a 30-inch, high pressure pipeline on mono-pile VSMs with freestanding thermosyphons.

227. A replacement property that does not incorporate all of the utility of the existing facility assumes that market participants do not place a value on all of the capabilities of the existing facility. But here, the evidence persuasively demonstrates that value has been placed on all of the capabilities of the existing facility including the ability of the 48-inch pipe to transport up to 2.1 million bbl/d of throughput. In effect, the Owners would redefine the subject property which is TAPS to instead constitute a pipeline that only transports the current throughput, with limited upward scalability. In this Court's view, such an approach is

[350] 10 N.J. Tax 114 (N.J. Tax Ct. 1988), *superseded by Chevron U.S.A. v. City of Perth Amboy*, 11 N.J. Tax 480 (N.J. Super. App. Div 1989).

[351] *Perth Amboy*, 10 N.J. Tax at 118.

[352] *Perth Amboy*, 10 N.J. Tax at 118.

[353] *Perth Amboy*, 10 N.J. Tax at 147.

inconsistent with appraisal theory and would result in a fundamentally improper valuation of TAPS. Instead, under appraisal theory, the statute's directive to accord "due regard" to the proven reserves and the current throughput should be addressed in the context of depreciation, and specifically economic obsolescence, of the subject pipeline.

228. Mr. Greeley, the State Assessor, testified that he had no specific knowledge of any cross-country pipeline in Alaska being valued by the Department based on a replacement cost new redesign that used a different diameter pipe than existed in the subject property.[354]

229. AS 43.56.060(e) directs that a pipeline be assessed "with due regard to the economic value of the property based on the estimated life of the proven reserves."[355] Under standard appraisal theory, this statutory language does not warrant nor require that the existing property's upward scalability be ignored.[356] Rather, the RCN should be based upon TAPS' actual design capacity. The fact that TAPS has upward scalability to carry throughputs of up to 2.1 million bbl/d enhances the pipeline's value. The Stantec design does not adequately incorporate this upward scalability.

d. The Stantec Design Is Unproven and Unknown

230. For many of the same reasons that this Court concluded that the Stantec design is not of similar quality and like utility to TAPS, the Court was not persuaded that the Stantec 30-inch pipeline design is physically possible and capable of being safely and effectively operated. The Stantec hypothetical 30-inch pipeline is, in part, based upon the

---

[354] Tr. 6851-52 (Greeley). *See also* Tr. 12679 (Greeley); Tr. 6905 (Goodwin) (testifying that common carrier pipelines in Alaska are not valued based on redesign studies).

[355] AS 43.56.060(e)(2) (emphasis added).

[356] *See generally Valuing Machinery and Equipment* at 99-100.

application of design criteria that are unproven for cross-country pipelines, including its high pressure and its mono-pile VSMs without internal or integrated thermosyphons.[357]

231. A proposed replacement property should actually exist or be based on a proven design and technology for a particular environment, rather than based on an untested concept that does not have the same capability or utility as the existing subject property.[358] This Court found Mr. Connolly's testimony regarding this topic to be particularly persuasive.[359]

232. When Stantec decided to use a 30-inch pipe for their cost estimate, they gave no consideration to a 1.1 million bbl/d throughput capacity.[360] That higher capacity was added several months later.[361]

233. Stantec uses six pump stations for its 2007 RCN, based on a design capacity of 900,000 bbl/d. It has five pump stations at the 750,000 bbl/d case for 2009.[362] To transport 1.1 million bbl/d, Stantec adds a seventh operating station.[363] This variation in pump stations for different throughputs is an indication that the Stantec design has minimal flexibility.[364] Mr. Hisey testified, "The 30-inch line that's running at or near its maximum design capacity, in my mind, wouldn't have much flexibility left. There wouldn't be much

---

[357] Tr. 4646-48 (Steindorff).

[358] Tr. 998-1003 (Connolly); *American Crystal Sugar Co. v. County of Polk*, 2009 WL 2431376 at 19 (Minn. Tax Regular Div. 2009).

[359] Tr. 999-1003 (Connolly).

[360] Tr. 3308-09 (Fiske).

[361] Tr. 8081-85, 8098-8100, 8111-12 (Modisette).

[362] Tr. 4472-73 (Steindorff). The 800,000 case for 2008 is also six pumps. Tr. 4472 (Steindorff); Tr. 5317 (Rein).

[363] Tr. 4472 (Steindorff).

[364] Tr. 4472-77 (Steindorff)

room for error. There wouldn't be much room for catch-up, either on day-to-day basis or a long-term basis."[365]

234. The Stantec design as proposed requires 80% drag reduction from DRA in order to be able to transport 1.1 million bbl/d.[366] Mr. Pietsch's initial simulation in November 2009 based on a lower design capacity assumed 50%-65% drag reduction was reasonable. But in December 2010, Mr. Pietsch increased that to 80% drag reduction after acknowledging that there was not enough horsepower in the pumps to transport 1.1 million bbl/d if only 65% drag reduction was achieved.[367]

235. Mr. Pietsch utilized 80% drag reduction in his 1.1 million bbl/d simulation but acknowledged that he does not know of any other cross-country crude oil pipeline that operates with over 50% drag reduction effectiveness.[368] Although Mr. Pietsch had authored papers on DRA reduction, he was not aware of any published literature using that high of a level of drag reduction.[369] The maximum DRA reduction that he has ever seen for a crude oil pipeline was a simulation of the original TAPS Legacy pumps at 60%.[370]

236. Stantec relied on a promotional ConocoPhillips web page regarding a DRA product that indicated an 80% drag reduction could be attained. But the 80% drag reduction advertised on the web page is for an unspecified light crude and does not indicate pipe diameter or velocity (both of which could affect DRA performance).[371]

[365] Tr. 4960 (Hisey).

[366] Tr. 2076-81 (Pietsch); Tr. 5148-49 (Riordan); Tr. 8078-80 (Modisette); Tr. 3865-66 (Ellwood), Tr. 4492-94 (Steindorff).

[367] Tr. 2076-79 (Pietsch); Tr. 8078-80 (Modisette).

[368] Tr. 2079 (Pietsch).

[369] Tr. 2079 (Pietsch).

[370] Tr. 2080 (Pietsch).

[371] Tr. 8103-07 (Modisette).

237. Dr. Modisette persuasively testified that there would be significant degradation of the DRA in the Stantec pipeline caused by the shear stress at the wall due to the higher flow velocity in the 30-inch pipeline.[372]

238. This Court was not persuaded that the requisite levels of drag reduction could be achieved on the Stantec pipeline.

239. Mr. Steindorff and Mr. Ellwood relied upon exhibit MUN7-1182, which lists seven pipelines with flow rates between 450,000 bbl/d and 1.0 million bbl/d, to support their opinion that the Stantec 30-inch pipeline design cannot effectively transport the actual throughputs during the lien years or the design criteria for TAPS.[373] All of these pipelines have a larger diameter than the Stantec pipeline. Consistent with these findings, several witnesses testified that they do not know of a 30-inch pipeline anywhere in the world today that operates in excess of 500,000 bbl/d.[374]

240. Mr. Pietsch acknowledged that he has never simulated a 30-inch diameter pipeline that was actually constructed in which the design capacity was 1.1 million bbl/d, 900,000 bbl/d or 700,000 bbl/d.[375] He has never before simulated a 30-inch crude oil pipeline that had one half the 1.1 million bbl/d flow rate of what he simulated in this case – i.e. 550,000.[376] Further, Mr. Pietsch did not know of a 30-inch crude oil pipeline anywhere in

---

372 Tr. 8113-14 (Modisette).

373 Tr. 6664-65 (Ellwood) (testifying that he relied upon exhibits MUN7-1196 to MUN7-1199, which include the underlying data for MUN7-1182); Tr. 4454-55 (Steindorff).

374 Tr. 3203 (Carson), Tr. 6895 (Greeley); Tr. 2029-30 (Pietsch); Tr. 6665 (Ellwood); Tr. 12500 (Remsha). *See also* Tr. 5297 (Rein) (testifying that he is not aware of a similar pipeline anywhere in North America or the world similar to the Stantec pipeline design).

375 Tr. 2029, 2072 (Pietsch).

376 Tr. 2029, 2031-32 (Pietsch).

the world that was operating at 1.1 million bbl/d.[377] And he acknowledged that Stantec's ability to transport any throughput above 1.1 million bbl/d would be very limited.[378]

241. Mr. Pietsch also indicated that he had not done a simulation to show that the Stantec Valdez Terminal could operate at 1.1 million bbl/d.[379]

242. Many of the Owners' witnesses expressed absolute confidence in the design of the Stantec RCN. But this Court was left unpersuaded that the high level of confidence that was expressed was supported by the evidence. In this regard, the Court notes that the very high level of confidence with the 30-inch Stantec design was in direct contrast to the markedly pessimistic testimony by the Owners' witnesses about the ability of TAPS to operate below 300,000 bbl/d.

243. The Owners failed to persuade this Court that the Stantec design could operate as designed. Rather, this Court finds its design is unproven and unknown.[380]

e. The Stantec Design Does Not Capture All Costs

244. An RCN cost estimate should include all of the indirect and direct costs necessary to actually engineer and construct the replacement property. This Court was not persuaded that the Stantec RCN adequately captured all those costs. To cite one example, Stantec's study is not close to final bid, yet it has a contingency of less than 4%.

---

[377] Tr. 2029-30 (Pietsch).

[378] Tr. 2086 (Pietsch)

[379] Tr. 2093 (Pietsch).

[380] Tr. 11541 (Hoffbeck).

f. The Stantec Design Does Not Permit Adequate Quantification of Obsolescence

245. This Court finds that using an RCN with a smaller design capacity in order to take into account the obsolescence inherent in a subject property which is not using all of its capacity would result in over-counting of depreciation if that same obsolescence is also deducted from the reduced sized RCN in the depreciation stage of the cost analysis.[381]

246. Additionally, adopting an RCN that is markedly dissimilar to the actual property being assessed and is instead designed based only on projected throughputs during each lien year would substantially increase the costs associated with determining the value of TAPS each year, since such an approach would likely require a new RCN each year with each increase or decrease in the throughput. In this regard, Mr. Hoffbeck's explanation of Mr. Treadwell's analysis is persuasive: the complications associated with a property redesign for a replacement cost study should be avoided. Instead, any obsolescence in the subject property may and should be cured with obsolescence adjustments to an RCN of similar quality and like utility to the subject property.[382]

247. The Stantec team has had extensive experience working in Alaska and other cold climates, as well as with Alyeska. Overall, this Court finds that the team effectively and capably undertook the task they were charged to undertake – to design a pipeline that appears to meet the minimum operating standards possible for crude oil transportation at the lowest cost, based on a design capacity determined from average daily throughput for each of the lien years. But, as explained in the above findings, that hypothetical pipeline is not an appropriate RCN to use to determine the assessed value of TAPS.

[381] Tr. 11543-54 (Hoffbeck).

[382] Tr. 1056 (Hoffbeck).

248. Alyeska employee Joe Riordan's loyalty and commitment to his employer was established beyond a reasonable doubt. And Mr. Riordan was very helpful to this Court in explaining some of the fundamentals of pipeline design and operations. And yet Mr. Riordan played a very active role in the development of the Stantec cost study. Indeed, he described himself as the "director" over the "cast" of experts for the Stantec RCN.[383] This Court finds it more likely than not that Mr. Riordan's extensive involvement in many aspects of the Stantec RCN constrained the experts from forming independent opinions and resulted in an effort to minimize the overall cost of the Stantec RCN even if not technologically justifiable.

249. Stantec's RCN uses a 30-inch pipeline with physical properties, operations, design capacity, and capabilities that are completely different from the existing TAPS. It so deviates from the existing TAPS that it can not serve as a reasonable proxy in a replacement cost new study. In addition, its unproven design, including its high operating pressures, high velocities, high operating costs, and design issues related to the VSMs and freestanding thermosyphons make it more likely than not that such a pipeline would never be built – which is perhaps best demonstrated by the fact that there is no existing pipeline in the world that bears any reasonable approximation to the Stantec design.

250. For the above-stated reasons, the Court finds that Stantec's 30-inch pipeline is not an appropriate replacement pipeline to use as the basis for the application of the cost approach.

[383] Tr. 1557, 1562 (Riordan).

3. The Pro Plus RCN

a. The Pro Plus Experts

251. The Pro Plus replacement cost estimate was prepared by pipeline and marine terminal engineers, contractors, and cost estimators with extensive experience, including engineer Gerald Steindorff, pipeline design expert John Ellwood, estimating and construction specialists Earl Tise and M. Kieth Phillips, and engineers Stan Lloyd and Jerry Baker, who specialize in marine facilities.[384] Each witness's qualifications were discussed on record in detail.

252. The Pro Plus experts have a combined total of over 250 years of hands-on experience in engineering, project management, estimating, and construction of pipelines and terminal facilities.[385] They have collectively estimated, managed and constructed several thousands of miles of cross-country pipeline in rugged terrain.[386] With the exception of Mr. Baker, all of the Pro Plus experts testified before this Court. Mr. Phillips testified by perpetuated video deposition.

253. In addition, Dr. Jerry Modisette conducted hydraulic modeling to analyze the viability of the Pro Plus and Stantec pipeline designs. Dr. Mark Cronshaw addressed the RCN contingencies.

b. The Pro Plus Design

254. The Pro Plus design is a 48-inch diameter pipeline that is of similar quality and like utility to the existing TAPS.

---

[384] Phillips Dep. 28.

[385] Tr. 4459-60 (Steindorff); Tr. 4076 (Ellwood).

[386] *See* Tr. 4080-8 (Tise); Tr. 3688-96, Tr. 3701 (Ellwood); Tr. 4460 (Steindorff); Phillips Dep. 71 (Aug. 22, 2011).

255. Pro Plus states that its design basis is 1.1 million bbl/d with upward scalability.[387] This is essentially the same design basis as the existing TAPS pumps.[388] But this Court finds that the Pro Plus 48-inch mainline pipe and VMT are comparable to the design capacity of the existing TAPS, which is 1.42 million bbl/d.[389]

256. Pro Plus's dual-pile VSM design is identical to the existing pilings and provides the necessary level of safety and protection against thawing of the permafrost as the existing facility.[390] Pro Plus spaces the VSMs at approximately 60 foot intervals, per DB-180 requirements.[391]

257. Pro Plus used floating roof tanks instead of the existing fixed roof tanks at the VMT. This Court finds that the Pro Plus VMT design is of similar quality and like utility to the existing TAPS.

258. Like TAPS, Pro Plus's pumps have three trains installed side by side, one pump per train.[392] The pumps are in parallel operation.[393] Pro Plus's operating stations each have the same installed horsepower as on the TAPS SR pumps.[394] However, Pro Plus has five operating stations, whereas the existing TAPS has four that have or will get the new SR pumps. Like the TAPS' SR pumps, the Pro Plus pumps have variable speed drive.[395]

---

[387] MUN7-0008 at 10.

[388] MUN7-9023 at 239; MUN7-1506 at 11, 13; MUN7-1553 at 6.

[389] MUN7-0215.; Tr. 3716 (Ellwood); Tr. 2731 (Falcone); Tr. 7139-40 (Ray); MUN7-1137; MUN7-1553 at 6-7; MUN7-1182.

[390] Tr. 3721 (Ellwood).

[391] Tr. 4500-02 (Steindorff); MUN7-9023 at 72; MUN7-0008 at 15. *See also* Tr. 3128-29 (Meyer).

[392] Tr. 4474 (Steindorff); Tr. 8085 (Modisette).

[393] Tr. 4474 (Steindorff).

[394] Tr. 4472 (Steindorff).

[395] Tr. 4472 (Steindorff).

Like TAPS, at each station, Pro Plus has three 6500-horsepower units. At lower throughputs, one set of pumps is unnecessary and serves as a spare.[396]

259. Pro Plus uses a granular work pad along most of the length of the pipeline.[397] A granular work pad provides the ability to work in multiple seasons, reduces the risk of non-completion, and provides summer access for continued maintenance of TAPS and contingency purposes.[398] Mr. Baldridge, an Alyeska employee, testified to the utility and benefit of TAPS having the current work pad.[399] The Court finds that Pro Plus's use of granular work pads is reasonable, and that the continued benefit of the existing work pads on TAPS would not be captured in an RCN of TAPS that used predominantly ice roads.

260. Pro Plus used the existing route of TAPS with some minor realignments – about three tenths of a mile – to facilitate directional drilling at some of the river crossings and in the Fairbanks area to avoid the buildup area that did not exist when the original route was selected.[400] The Court finds that Pro Plus's route has the same utility as the current route and the slight deviations are reasonable.

261. The Owners established that Pro Plus's estimate did not include all of the essential components for a pipeline from PS 1 to Valdez – for example, the Pro Plus estimate did not include safety flares at PS 1.[401] But the goal of an RCN estimate is for

---

[396] Tr. 4472-73 (Steindorff); Tr. 8085 (Modisette).

[397] Tr. 3862-63 (Ellwood).

[398] Tr. 1243-45 (Baldridge); 3862-63 (Ellwood).

[399] Tr. 1243-45 (Baldridge); 3862-63 (Ellwood).

[400] Tr. 3719-20, 3861 (Ellwood); Tr. 4471, 4512 (Steindorff).

[401] Tr. 1595 (Riordan).

comparison purposes to an existing property. It is not intended to be a fully detailed, comprehensive cost estimate.

c. The Pro Plus Cost Estimate

i. Direct Costs

262. In preparing pipeline construction estimates, costs are identified as direct and indirect. The Pro Plus estimate categorizes the following direct costs: Survey, Pipeline Material, Pipeline Installation, Pump Station Facilities, Pump Station Installation, Meter Station Facilities, Meter Station Installation, Valdez Marine Terminal, and Pipeline Systems.[402] Pro Plus estimated the direct costs at $11.4 billion for 2007, $12.5 billion for 2008, and $12.4 billion for 2009.[403]

a) Pipeline Materials

263. The Pro Plus RCN utilizes many of the original quantities for TAPS to determine the necessary pipeline material. Pipe diameter, wall thickness, grade, and lengths used are those described in the "Alyeska Facts" booklet.[404] The line pipe estimate includes the 48-inch pipe used to transport crude oil, the 8-inch and 10-inch pipe used to transport fuel gas, and the 18-inch pipe used for the VSM:

> [W]e have carefully reviewed these quantities, sizes, etc. and have concluded they are still the most appropriate for the 1.1 million barrel per day design flow used as the basis for the RCN estimates. Maintaining the pipe diameter, wall thickness, etc. the same as the original design should not be confused with the use of modern versus 1970's materials. The estimated costs presented herein are based on up to date material specifications, steel pipe manufacturing process, coatings, welding processes, etc. Utilizing the same diameter and wall thickness for the pipe provides the same functionality as the

[402] MUN7-0008 at 1628; Tr. 3726-27 (Ellwood); Tr. 4634-35 (Steindorff).

[403] MUN7-0008 at 1628.

[404] MUN7-1103.

> existing facilities while minimizing costs through use of modern materials and construction methods.[405]

The Alyeska Facts book is updated regularly and contains one of the best public sources of the actual materials in place on TAPS.

264. The Pro Plus team then developed C-plans, which Mr. Ellwood and Mr. Tise explained are used to generate "a take-off of things that needed to be included in the [Pro Plus] estimate," such as the contours and grades of the terrain, the number of flume pipes, the river and road crossings, and the placement of valves.[406] As an example, referencing Aerial Maps 27 and 28 of the C-Plans, Mr. Tise testified:

> I used that to indicate that we left the pipeline above ground at mile 12 1/2; and if you will look at Aerial Map 28, you will see that below mile 53 – in fact, I think we carried it as 53 1/2. But you will notice that the pipelines come from belowground to above ground. So it's been 40 miles of pipe belowground.[407]

265. After some study, Pro Plus adopted the above and below ground configurations on the existing TAPS.[408] Mr. Tise calculated the number of miles of above and below ground pipe for each section, indicating the mile where the pipe transitions from above to below ground,[409] then used the Alyeska Atlas to verify his takeoffs.[410]

266. For the VSMs, Mr. Ellwood and Mr. Steindorff testified that they used information provided by the Joint Pipeline Office ("JPO") to determine the amount of steel

---

[405] MUN7-0008 at 14.

[406] Tr. 3743-44; 3791 (Ellwood); Tr. 4117-38 (Tise) MUN7-1100.

[407] Tr. 4133 (Tise); MUN7-1100 at 155.

[408] MUN7-0008 at 9; Tr. 4133-34 (Tise)

[409] Tr. 4145 (Tise); Tr. 4449 (Steindorff); MUN7-1113 at 6-9.

[410] Tr. 4133, 4145-46; MUN7-1101.

needed for the VSMs and then calculated the weight of that steel and obtained budgetary quotes to fabricate the VSMs.[411]

267. Pro Plus utilized the same grade of line pipe as the existing TAPS – X-65 and X-70, with wall thicknesses of .462 inches and .562 inches.[412]

268. The Owners critiqued Pro Plus's choice of X-65 and X-70 grade steel instead of the X-80 grade that was used in the Stantec cost estimate.[413] X-80 grade has a greater yield strength and would have been necessary for the higher pressure on Stantec's 30-inch pipe.[414] But Mr. Steindorff persuasively testified that X-65 and X-70 grade steel are the most appropriate and most economical choice for the 48-inch pipeline.[415] A thinner, higher grade pipe could cause problems with the 48" pipe such as ovality, buckling and bending.[416] The evidence also demonstrates that X-65 and X-70 are commonly used steel strengths in modern pipelines.[417]

269. Mr. Steindorff provided a detailed explanation on how Pro Plus derived the materials costs of its 48-inch mainline pipe.[418] Pro Plus estimates that a 48-inch mainline pipe would cost $1,791 per ton for 2007, $2,548 for 2008, and $2,033 per ton for 2009.[419]

---

[411] Tr. 3798, 3869-70 (Ellwood); Tr. 4449 (Steindorff); MUN7-1109. Pro Plus had this information regarding the steel members before the 2006 ad valorem tax matter and it was incorporated into the study presented to this Court. Tr. 3870 (Ellwood).

[412] Tr. 3716-17 (Ellwood); Tr. 4509-12 (Steindorff).

[413] Tr. 5090-92 (Riordan).

[414] Tr. 1589 (Riordan); Tr. 2953 (Ziehr).

[415] Tr. 4511-12, 6618-19 (Steindorff). *See also* Tr. 3716:16-17, 3892-94 (Ellwood).

[416] Tr. 3716-17 (Ellwood); Tr. 4509-12 (Steindorff).

[417] *See e.g.*, Tr. 5449 (Jens); Tr. 6499-6500 (Tise); Tr. 6534-35 (Tise).

[418] Tr. 6599-6602 (Steindorff).

[419] Tr. 6599 (Steindorff); MUN7-0008 at 44, 575, 1107.

Pro Plus solicited quotes directly from several North American mills (rather than obtaining them as Michels Canada did from pipeline distributors for Stantec).[420]

270. Logistically, Pro Plus railed the pipe to Seattle for transport by barge and rail to Valdez and Fairbanks to double-jointing yards.[421] From the double-jointing yards, the pipe would be trucked to stockpiles along the right-of-way for use by the pipeline contractor.[422]

271. At trial, Pro Plus indicated that its materials estimates should not have included a line item for insulation of the work pad, which they had estimated at approximately $34 million per year.[423]

b) Pipeline Installation

272. Pro Plus relied upon numerous documents to determine the costs for the pipeline installation, together with their expertise and experience. These documents included the Alyeska Contingency Plan ("C-Plan") drawings, Alyeska Facts booklet, TAPS ROW Map Atlas, Google Earth, and the Alyeska alignment sheets (G-100 Drawings).[424]

273. The Owners' experts particularly criticized Pro Plus's productivity rates, labor rates, and equipment rates.

274. Productivity rates can be impacted by several factors, including weather, terrain, time of year, start and completion dates, environmental restrictions, contractor availability, and the availability of labor and equipment.[425]

---

[420] Tr. 6599-6600 (Steindorff) (relying on MUN7-1105).

[421] Tr. 6600 (Steindorff); MUN7-1106 at 1-4.

[422] Tr. 6600 (Steindorff); MUN7-1106.

[423] *See, e.g.* MUN7-0008 at 1107.

[424] Tr. 3792-93 (Ellwood); Tr. 3793-94 (Ellwood); Tr. 4117-18 (Tise); MUN7-1100; MUN7-1101; MUN7-1103.

[425] Phillips Dep. 37, 39, 40, 43, 44, 46, 47, 51, 52.

275. Mr. Tise discussed in detail how March Charts and crew-up sheets were created and utilized by Pro Plus to determine pipeline installation costs.[426] He explained how the C-Plans assisted in the determination of the progress rate in each section. For example, utilizing page 125 of the C-Plans,[427] Mr. Tise stated:

> [i]f you can look at the contours, you can see how close they are together, being in that section, it's going uphill from just below Pump Station 12. And from experience, I know that those grades are 30 percent to 70 percent; and I know that they were also – more than half of them were rock. So that helped in crewing-up, seeing how much progress we could get. And then if you look above Pump Station 12, you notice that it's flat. So we have designations from flat to mountain, of about six of them, that just increase in the degree of difficulty ... This section was about 147 miles. And we came up with how much of it was flat, how much of it was rolling, and so forth to come up with progress rates.[428]

276. The Owners' experts argue that Pro Plus's productivity rates for welding are too low, and therefore affect the overall construction schedule. However, based on the evidence presented, this Court finds that the welding rates do not control the pace of the Pro Plus RCN construction project.[429] Mr. Ellwood persuasively testified that "[i]n a pipeline job, the whole operation must move only as fast as the slowest crew. And in our view, what we call putting the pipe in the ditch or, in this case on the VSMs, in places will control the pace for the most of this project."[430]

---

[426] Tr. 4147-50, 6529-30 (Tise); MUN7-1115; MUN7-1116;Phillips Dep. 23-24; Tr. 3747-48 (Ellwood); Tr. 4147-48 (Tise); Tr. 4449 (Steindorff); MUN7-1115; Phillips Dep. 23-24, 25-26, Tr. 3749-50 (Ellwood), Tr. 4147-48 (Tise); MUN7-1115.

[427] MUN7-1100.

[428] Tr. 4120-21 (Tise).

[429] Phillips Dep. 37-39; Tr. 3740 (Ellwood).

[430] Tr. 3740 (Ellwood).

277. In determining the productivity rate, Pro Plus also considered the shortage of pipeliners during the lien years due to extensive pipeline construction activity in the United States during that time.[431] Given that shortage and the remote and isolated location of Alaska, Mr. Tise testified that in the lien years,

> [y]ou're not going to get the A team and you're not going to get the B team; they're all already working ... the journeymen hours are for those three years [It's] more than any three-year – back ... to 1965. Even including the years that [TAPS] was being built, you've already exceeded the man-hours for those years by about 300 percent . . . .[432]

278. In addition, Pro Plus took into account that 420 miles of the pipeline will be above-ground and that those portions will take longer to install because the pipe has to fit into all the VSM supports through challenging terrain.

279. Regardless of what work sets the pace for the pipeline construction, this Court finds that Pro Plus's overall welding rates are reasonable.[433] Pro Plus estimates approximately 50 joints per day.[434] As Mr. Phillips explained, the welders will have to achieve 75 joints on some days in order to achieve an average of 50 joints per day because there will be days in which none or very little welding is achieved due to weather, delays in the other crews, or equipment failures.[435]

280. Pro Plus's estimate includes the cost of automatic welding for sections 1, 3, 4, and 5 and manual welding for sections 2 and 6.[436] Pro Plus assumed that because manual

---

[431] Phillips Dep. 39-42.

[432] Tr. 4168 (Tise). *See also* Phillips Dep. 39-42 (relying on MUN7-1201 (Hours Worked in the Pipeline Industry, Historical (Cash) Based (1965-2011)).

[433] *See* Tr. 4152-56 (Tise); Phillips Dep. 63-64.

[434] Phillips Dep. 52-53.

[435] Phillip Dep. 52-54.

[436] Phillips Dep. 56-57, 62; Tr. 4462 (Steindorff).

welding would be needed in difficult constructions areas in sections 2 and 6 -- specifically in Atigun Pass and Thompson Pass[437] -- manual welding should be used in each of those entire sections.

281. This Court found the Owners' critique on this issue persuasive. That is, this Court was unpersuaded that because of the challenges presented by Atigun Pass and Thompson Pass, the entire two spreads that encompassed those passes should be manually welded.[438] But overall, this Court finds that Pro Plus's productivity rates are reasonable.

282. The majority of the experts acknowledged that the owners, contractors, and unions would negotiate and enter into a project labor agreement for the construction of a pipeline system and marine terminal of the length, size, and complexity of TAPS.[439] Mr. Ellwood persuasively testified that before committing the billions of dollars needed to build a pipeline, a project labor agreement would be needed to provide some certainty to the labor situation.[440]

283. An owner that was contemplating the building of a new TAPS would want to assure predictability, labor certainty, and a "no-strike" condition to assure the completion of the project.[441] Contractors would need to know the rates they would have to pay their labor

---

[437] Tr. 4462-63 (Steindorff).

[438] Phillips Dep. 59-60.

[439] Tr. 3751 (Ellwood); Phillips Dep. 73-74; Tr. 2994 (Ziehr); Tr. 5427 (Jens); Tr. 6159 (Bock); Tr. 5656 (Sherman); Tr. 5801 (Karlik); Tr. 4938 (Dotson) (indirectly); TO-07-0021 at 0700; Tr. 4427 (Steindorff).

[440] Tr. 3751 (Ellwood).

[441] Phillips Dep. 86; Tr. 3751 (Ellwood).

force prior to bidding the project. The unions would want to ensure their members obtain adequate wages, benefits, and living and working conditions.[442]

284. This Court finds that the evidence persuasively showed that a labor agreement for constructing TAPS would start with the Pipe Line Contractors Association ("PLCA").[443] The PLCA negotiates wages, benefits, working conditions, and other terms with the four main pipeline trades (Journeyman, Laborers, Teamsters, and Operators) and publishes the labor rates for each state annually.[444] However, no labor rate has been published by the PLCA for Alaska during the years at issue in this litigation.[445]

285. Pro Plus's estimate tries to determine what the outcome of the PLCA negotiation would have been.[446] Pro Plus did not call any local Alaska labor unions to determine their current rates, even for those trades that are not covered by the PLCA.[447] Labor rates from local unions typically are lower than PLCA rates.[448]

286. Pro Plus's estimate assumes that all workers doing similar work will be paid the same regardless of the location of their assignments.[449] For example, Pro Plus assumes that a crane operator working on the pipeline and a crane operator working at the VMT would both receive the same wages because the project labor agreement would be negotiated to cover all workers. At least with respect to work at the VMT, this Court was not

---

[442] Tr. 3751-53 (Ellwood).

[443] Phillips Dep. 73-74; Tr. 3751-52 (Ellwood); Tr. 2994 (Ziehr); Tr. 4938 (Dotson); TO-07-0021 at 0700; Tr. 4494-95 (Steindorff); Tr. 5656 (Sherman).

[444] Phillips Dep. 12-13, 73-74; Tr. 3752 (Ellwood), 4143 (Tise); MUN7-1117 at 8-9.

[445] Tr. 3754 (Ellwood).

[446] Tr. 4494-95 (Steindorff); Tr. 3752; Tr. 3754, 4033-34 (Ellwood).

[447] Tr. 4033-34 (Ellwood).

[448] Tr. 4497 (Steindorff).

[449] Phillips Dep. 87-89; Tr. 4426-27 (Lloyd).

persuaded that this assumption was reasonable. Rather, more likely than not a worker who was expected to stay in camps and operate cranes at remote locations along the pipeline route would expect and obtain a higher wage than a crane operator who would be residing in Valdez for the duration of his employment on the project.

287. The Pro Plus study utilized the published PLCA rates for California for each year and added approximately 15% as a likely incentive to get workers to Alaska for the job.[450] Pro Plus also added double time for Sundays and included four hours wages per day when the worker was off-duty (paid only when the worker returned to the job).[451] Pro Plus experts testified that the remote location, the camp and weather conditions, and the worker's isolation from their families warranted these adjustments to the labor rates that would be negotiated for the construction of TAPS.[452]

288. Pro Plus did not include any per diem or welder rig rates;[453] had they done so, their estimated rates estimated would have been higher.[454]

289. Relying on a comparison of a Lower 48 journeyman rate with the Alaska journeyman rate during construction of TAPS in the 1970's, Mr. Tise noted that the increase in wages for Lower 48 journeymen working in Alaska for construction of TAPS was between 19 – 28%.[455] That range is higher than the rate utilized by Pro Plus, which added 15% to the California rates.[456]

---

[450] Phillip Dep. 31-32, 73, 78-79; Tr. 3762-63 (Ellwood); Tr. 5669-70 (Sherman).

[451] Phillips Dep. 84-85; Tr. 3762-63 (Ellwood).

[452] Phillip Dep. 31-32, 73, 78-79, 84-85.

[453] *Cf.* TO-07-0044 at 0068.

[454] Phillips Dep. 81-82.

[455] Tr. 4141-42 (Tise); MUN7-1117 at 3.

[456] Phillips Dep. 77-78; Tr. 3766 (Ellwood); Tr. 4140 (Tise); MUN7-117 at 8-17; MUN7-1205.

290. The Owners hired Hawk Consultants LLC ("Hawk") to critique the RCN estimate prepared by Pro Plus for the 2007 to 2009 lien years. The Hawk experts did not present a comprehensive critique of the Pro Plus estimate, but only looked at certain limited topics. And each Hawk expert only reviewed his assigned portion of the Pro Plus estimate and did not read any depositions of Pro Plus experts or their transcripts either before this Court in the 2006 litigation or before SARB in 2009, 2010, or 2011.[457]

291. Jeff Sherman was one member of the Hawk team who looked at labor rates. Of note, Mr. Sherman's overall production cost per mile for the welding crew (which would have necessarily included all of those factors) was very close to that of Pro Plus's estimate.[458] Mr. Sherman calculated that the Pro Plus cost per mile for their welding crew was $98,712.[459] Hawk's cost per mile was $98,907.[460]

292. Overall, this Court finds that Pro Plus's rates for the four PLCA trades are reasonable, including its use of the California base rate with 15% markup, except that this Court was persuaded by the Owners' experts that the use of Sunday double time and compensation at the rate of four hours per day on off dates would, more likely than not, not be included within a project labor agreement.

293. Pro Plus determined the wage rates for the remaining trades and the salaried staff by adjusting from the PLCA rates. But this Court was persuaded by Mr. Sherman's testimony that the labor rates used for the non-PLCA trades and the salaried staff in the Pro Plus estimate are generally too high. While some upward adjustment to those wages from

[457] Tr. 5637 (Sherman).

[458] Tr. 5677 (Sherman).

[459] Tr. 5676-77 (Sherman).

[460] Tr. 5676-77 (Sherman). *See also* TO-07-0044.0075; Tr. 5715-16 (Sherman).

Alaska labor rates is warranted due to the fact that a project of this magnitude will necessarily increase the cost of labor and due to the remoteness of the work, overall this Court finds that Pro Plus's adjustment overcompensated for these factors for the non-PLCA trades and the salaried staff.

294. To determine equipment rates, Pro Plus used bids from previous big-inch, cross-country pipelines information from Caterpillar Company, and prices for 2007, 2008, and 2009 from PipeLine Machinery, a pipeline rental/sales company in Houston.[461]

295. Hawk consultant witnesses criticized the Pro Plus cost estimate for having equipment on site for the full duration of the construction. Mr. Ellwood testified that it is necessary to have equipment for the duration of the project because in many of the construction sites equipment will not be available, particularly on short notice.[462] Pro Plus testified that there is a limited amount of construction equipment available for rent in Alaska. For example, Mr. Tise testified that in 2008, there was no 594 sideboom in Alaska to rent.[463] Contractors also do not want to rely upon small-scale dealers to service their needs so they will not rent locally.[464] Equipment rented out of state entails additional cost to winterize it and transfer it to Alaska.[465] But this Court was persuaded by the Hawk experts that there appears to be at least some instances where the Pro Plus estimate had included too much or too many days of equipment in its estimate.

---

[461] Phillips Dep. 31, 93-98; Tr. 4162-64 (Tise); MUN7-1118.

[462] Tr. 3738 (Ellwood). *See also* Phillips Dep. 69-71.

[463] Tr. 6529 (Tise).

[464] Tr. 4024 (Ellwood).

[465] Tr. 3775 (Ellwood).

296. Pro Plus applied a mark-up of 15% of the subcontract amount for a handling fee.[466] Hawk Consultants assert that this percentage is too high.[467] This Court was persuaded that a 15% handling fee for handling the subcontracts in this case is too high, and that 10% would be a more appropriate amount -- the same amount that Pro Plus applied to owner's costs, which has somewhat comparable oversight responsibilities.

297. Mr. Tise and Mr. Steindorff provided detailed explanations on how Pro Plus derived their pipeline camp cost estimates.[468] They also explained their reliance on the budgetary quote from International Camp Sales and Services, Inc., and the additional costs that were not included in that bid such as transportation to the site, erection costs, commissioning costs, and single man sleepers.[469] While the original TAPS construction had 29 camps, Pro Plus reduced the number of camps necessary to 6 larger camps and a total of 13 camp locations. The total camp capacity is 10,750 beds.[470] Pro Plus has anticipated in its RCN that "the peak manpower will be approximately one-third of the peak manpower during the initial construction."[471]

298. While the Owners' experts from Hawk critiqued the Pro Plus pipeline camp estimates, the Stantec estimates were higher. For example, in 2009, Stantec estimated

[466] MUN7-0008 at 95, 96.

[467] Tr. 5969 (Bock).

[468] Tr. 4158-61 (Tise); Tr. 6606-08 (Steindorff); MUN7-0008 at 737.

[469] Tr. 4937-4938 (Dotson). *See also* Tr. 4937-38 (Dotson); Tr. 4158-61 (Tise); Tr. 6606-08 (Steindorff) (relying on MUN7-1112 at 8-10).

[470] MUN7-0008 at 17. *See also* MUN7-1103 at 14.

[471] MUN7-0008 at 17

camp costs at $1.6 million,[472] while Pro Plus estimated camp costs for that year at approximately $1.4 million.[473]

299. For these reasons, the Court finds that the Pro Plus experts adequately demonstrated that their cost estimate for the pipeline camps is reasonable.

300. Pro Plus included a line item for miscellaneous expenses that will be incurred by the contractor totaling 40% of direct labor for each lien year.[474] Within the miscellaneous expenses, Pro Plus includes 20% of direct labor for small tools and consumables.[475] Mr. Phillips and Mr. Tise testified that 20% of direct labor for small tools and consumables is typical for contractors.[476] But based on the totality of the evidence presented at trial on this issue, this Court finds these amounts should be no more than 10% of direct labor. Pro Plus has also accounted for the cost of safety orientation, environmental orientation, background checks, physicals, and administrative work related to turnovers within the 40%, and Pro Plus has assumed that these costs will be 15% of direct labor costs.[477] With respect to these items, this Court also found Hawk's analysis persuasive, and concludes that these expenses should total no more than 10% of labor costs. Pro Plus also calculated that the contractors will incur 5% of direct labor costs for unscheduled overtime. But this Court finds that including this as a separate entry in addition to the 30% adjustment that Pro Plus identifies

---

[472] TO-07-0025 at 0651.

[473] MUN7-0008 at 42 ($712,195,300 for camp materials) and MUN7-0008 at 204, 253, 303, 352, 401, 450 (approximately $113,000,000 for pipeline camp installation cost for spreads 1-5 and $144,000,000 for spread 6).

[474] Phillips Dep. 93-99. *See, e.g.,* MUN7-0008 at 58, 95, 114, 132, 150, 169, 186, 203.

[475] Phillips Dep. 94-97, 98.

[476] Phillips Dep. 94-95.

[477] Phillips Dep. 96-98

for "weather equipment labor" entails a significant risk of double counting.[478] With these adjustments, this Court finds that the total miscellaneous expenses should be no more than 20% of direct labor.

301. Pro Plus's estimate also includes a 30% contractor's risk for "weather equipment labor."[479] Typically this cost is embedded in the contractors' bids, and the owner does not know the exact percentage utilized in the contractor's bid.[480] In a project of this size and scope, the contractor will assume a certain amount of risk associated with weather, equipment, and labor in its bid.[481] But this Court found persuasive the Owners' assertion that Pro Plus's estimate of this amount is too high. Given the other concerns separately identified with respect to the over-estimation of equipment usage and staff and non-trade wage rates, no more than 25% should be allocated for contractor's risk in the Pro Plus bid, an amount comparable to the overall contingency that has also been included in the Pro Plus cost estimate.

c) Pump Station Facilities

302. Pro Plus's estimated costs of the pump and meter stations are based on the design specified in the "Alyeska Facts" booklet, the "Pipeline Oil Discharge Prevention and Contingency Plan" ("C-Plan"), and the Design Specification for the SR project currently being implemented, along with modern design and construction techniques common to the industry.[482] Budgetary quotes were obtained for major equipment and material.[483] For other

---

[478] Phillips Dep. 96-97.

[479] Phillips Dep. 100-101.

[480] Phillips Dep. 19-22.

[481] Phillips Dep. 100-103.

[482] Tr. 4460-61 (Steindorff).

items, Pro Plus relied on estimates based on previous project experience and a historical database.[484]

303. The 2007 "Alyeska Facts" booklet states that there are six pump stations that were then currently operating: Pump Stations ("PS") 1, 3, 4, 5, 7 and 9. Of these, PS 5 is a relief station that does not contain mainline pumps.[485] PS 7 currently has the original Legacy pumps. The 2007 Facts book does not include PS 7 as one of the pump stations that is scheduled for the strategic reconfiguration (SR) pump upgrades.[486] In an order dated April 6, 2005, the RCA concluded that "pump stations 7 and 12 are no longer necessary for future TAPS operation."[487] However, PS 7 is the location of Alyeska's current recirculation project to increase the heat of the oil without the cost of acquiring a heater.[488]

304. The Pro Plus cost estimate generally follows SR and DB-180 and the SNC Lavalin Study with respect to the pumps, tanks, fuel gas line, power generation, and maintenance systems.[489] But the Pro Plus cost estimate differs by designing PS 7 to have the newer SR pumps and by adding pig launchers and receivers to further simplify pipeline operations.[490] The existing PS 7 does not contain any SR pumps as of the respective lien dates, nor is there any electric utility tie-in to PS 7.[491] Upon consideration of all the evidence, this Court finds Pro Plus's inclusion of PS 7 with SR pumps in its RCN was not

---

[483] Tr. 4451 (Steindorff); MUN7-1100; MUN7-1103; MUN7-1127-1131; MUN7-0008 at 23-24.

[484] MUN7-1127 to MUN7-1131.

[485] MUN7-1103 at 48. *See also* Tr. 3724 (Ellwood).

[486] MUN7-1103 at 56.

[487] MUN7-1506 at 11.

[488] Tr. 9011-13 (Modisette).

[489] Tr. 4460-61 (Steindorff).

[490] Tr. 4513 (Steindorff).

[491] Tr. 1200 (Baldridge).

unreasonable, and that the difference between the Pro Plus RCN and the existing TAPS in this regard is best addressed in determining depreciation.

305. Pro Plus's design did not include a PS 12, although that station may be necessary to the cold restart operations of TAPS. Given that TAPS has not ever used PS 12 for cold restart, the omission of this pump station from the Pro Plus RCN was reasonable. In any event, if PS 12 was required it would increase the cost of the RCN.[492]

306. Pro Plus created schematics, process flow diagrams, and conceptual layout plans for the pump station facilities.[493] The Owners' experts criticized Pro Plus for not including certain items in their process flow diagram.[494] But the process flow diagram was created to show the main flow of the crude oil; it was not intended to show auxiliary systems and minor piping.[495]

307. Owners' expert Mr. Riordan persuasively testified that the majority of the pipeline in the Pro Plus pump station was 48 inches which was unnecessary and costly.[496] Instead, smaller diameter piping can be used within the pump stations.

308. The Pro Plus installation costs of the pump stations are based on modular construction and developed utilizing the same "crew up" methodology that Pro Plus used for the pipeline installation. Mr. Ellwood and Mr. Tise persuasively testified that the "crew-up"

---

[492] *See* Owners' Proposed Findings of Fact and Conclusions of Law ¶ 58. *See also* Tr. 1199-1200 (Baldridge).

[493] Tr. 3744-45; 3746 (Ellwood); Tr. 4451; MUN7-1132.

[494] Tr. 1640-43 (Riordan); Tr. 4513-16 (Steindorff).

[495] Tr. 4514 (Steindorff) (discussing MUN7-1132 at 11).

[496] Tr. 5097-99 (Riordan). *See also* Tr. 4516-17 (Steindorff). The piping into the pumps is 24 inches. Tr. 4516-17 (Steindorff); Tr. 3732 (Ellwood).

method is used by contractors for facility work because it provides detailed information, such as the equipment, manpower, and the duration required for the work.[497]

309. A comparison of Pro Plus's direct cost estimate for pump stations with Stantec's is helpful.[498] In 2007, Stantec's estimate for the direct cost of pump stations is $812,871,643 for its 900,000 bbl/d throughput design. The additional cost for the 1.1 bbl/d throughput totals $415,044,990, for a total cost of approximately $1.2 billion.[499] Pro Plus's estimate of the total direct cost for all the pump station facilities, including installation and materials, is comparable at $1.0245540 billion for the 2007 lien year.[500]

310. Apart from the concerns identified as stated above (including those identified with respect to pipeline installation that would be applicable here as well), based on the evidence presented at the de novo trial, this Court is persuaded that overall Pro Plus's cost estimate for pump stations resulted in a proper valuation.

d) Valdez Marine Terminal

311. Lloyd Engineering performed the estimating work for the VMT portion of the Pro Plus estimate. Mr. Lloyd estimated the terminal facilities taking into account the relationship between the terminal, the pipeline minimum and maximum capacities, pipeline shut down allowance, the weather in Valdez, and berth availability for the tanker fleet.[501]

---

497 Tr. 3732-42, 6652-54 (Ellwood); Tr. 4117-18 (Tise); Tr. 4495-96 (Steindorff).

498 *Compare* TO-07-0021 at 546, 684 *with* MUN7-0008 at 41-42.

499 TO-07-0021 at 546, 684.

500 MUN7-0008 at 41-42 ($507,139,600 plus $495,315,800).

501 MUN7-0008 at 25-26.

The evidence demonstrated that the Pro Plus VMT design matches the flexibility of the 48-inch pipeline design and maintains the current flexibility of TAPS.[502]

312. Mr. Lloyd estimated a lay berth and two loading berths in the Pro Plus VMT.[503] The Owners critique the inclusion of the third lay berth. However, the evidence convincingly shows that the existing third berth is used and useful to TAPS and should be maintained. For example, in a December 2008 application to the RCA to decommission berths 1 and 3 for crude off loading purposes, the Owners stated that they intend "to continue using Berth 3." They added that:

> [a]part from loading crude oil, "Berth 3 is currently and frequently used and useful as a layover berth in various circumstances, as for example, when Hinchinbrook Entrance is closed due to adverse weather conditions in the Gulf of Alaska, for crew member medical evacuations, for vessel repairs, or in support of oil spill drills.[504]

313. Alyeska employee Tom Stokes agreed that the third berth has been used occasionally at the VMT, such as when the VMT was forced to close down and the pipeline was required to go into proration because of bad weather.[505]

314. The Court finds that two loading berths and one lay berth should reasonably be considered part of the existing useful property as of each of the lien dates and included in the RCN.

315. The Pro Plus cost studies advanced for the years 2007 through 2009 use floating roof tanks, unlike the 2006 study.

---

[502] Tr. 4477, 6451-52 (Lloyd). Mr. Stokes, Alyeska employee, testified that there is no minimum throughput limitation for the existing VMT to function. Tr. 3453 (Stokes). Mr. Stokes further testified that none of the projects that are currently being considered at the VMT would impact the throughput or the availability of the facility. Tr. 3453 (Stokes).

[503] Tr. 4355-56 (Lloyd); MUN7-9020; MUN7-1522 at 6.

[504] MUN7-1522 at 6.

[505] Tr. 3459-60 (Stokes). *See also* Allen Dep. at 26 (discussing bad weather in Valdez disrupting operations).

316. As in the 2006 ad valorem tax matter, Mr. Lloyd indicated that his VMT estimate is based on a 1.1 million bbl/d throughput. But he also considered new information as to the lower flow rates possible on the pipeline.[506] In order to match the range of capacity of the pipeline, Mr. Lloyd changed his estimate to utilize internal floating roof tanks.[507] Properly designed floating roof tanks will provide greater flexibility for throughputs of less than 1.1 million bbl/d.[508]

317. Mr. Lloyd testified that he maintains his concerns about using internal floating roof tanks in a severe seismic zone.[509] As in the 2006 appeal, he again looked to the 2003 Tank Consultant, Inc. ("TCI")/Nyman Report.[510] These were consultants hired by Alyeska to evaluate the use of floating roof tanks at the VMT; their report has not been updated. Mr. Lloyd accounted for the cautions expressed in the TCI/Nyman report by limiting the operating volume of the tanks to approximately 430,000 barrels versus the stated capacity of 510,000 barrels in each of the existing tanks.[511]

318. But with the decreased tank volume, the needed number of tanks increased from the 15 tanks in operation at TAPS during the lien years to 18, including one spare.[512] Mr. Lloyd's estimate provided sufficient storage for 6.6 days of throughput at 1.1 million bbl/d, with a total capacity of 7,222,000 barrels.[513] The total capacity of the existing 15 tanks is 7,650,000 barrels.[514]

---

[506] Tr. 4345-51 (Lloyd); MUN7-0008 at 27; MUN7-1553 at 6 (Section 5.2); MUN7-218 at 19.

[507] Tr. 3721 (Ellwood); Tr. 4359-60 (Lloyd).

[508] MUN7-0008 at 26.

[509] Tr. 4363 (Lloyd).

[510] Tr. 4363-66, 4373-74 (Lloyd); MUN7-1552; MUN7-1508.

[511] Tr. 4326-66 (Lloyd); MUN7-0008 at 31-32.

[512] Tr. 4365-67 (Lloyd); Tr. 3454 (Stokes) MUN7-0008 at 31-32. *See also* MUN7-1519.

319. Mr. Stokes of Alyeska testified that during 2007 through 2009 there were 15 tanks in service at the VMT. He also confirmed that currently only 13 tanks are in actual use, with the two additional tanks undergoing cleaning and inspection.[515] A total of 18 tanks were originally constructed at the VMT. Mr. Stokes agreed that the additional three out-of-service tanks provide more flexibility to the Owners should a reason to put them back into service arise.[516]

320. This Court finds that the Pro Plus tank design is a reasonable replacement for the existing TAPS tank design, and is reflective of the design capacity of the existing VMT, which is at least 1.42 million bbl/d. In fact, the existing VMT handled throughputs of 2.1 million bbl/d when all of its 18 tanks were in operation.

321. Pro Plus has estimated 10 million cubic yards of excavation will be needed to construct the VMT site.[517]

322. Mr. Lloyd testified about the excavation work when the VMT was originally constructed. He explained that "the amount of material excavated in the Terminal had escalated from a planned 4 million cubic yards to approximately 15 million cubic yards."[518] In any modern Greenfield development of the VMT site, the same soil conditions would be present as existed during the original construction.[519] As in the 2006 de novo trial, Mr. Lloyd persuasively testified at the current proceeding that it would be essential to fill behind

---

[513] MUN7-0008 at 32.

[514] MUN7-9023 at 333.

[515] Tr. 3454-55 (Stokes).

[516] Tr. 3458 (Stokes).

[517] Tr. 4358-59 (Lloyd).

[518] Tr. 4358; MUN7-1513.

[519] Tr. 4381-82 (Lloyd).

Jackson Point.[520] Overall, this Court was persuaded that Pro Plus's estimated 10 million cubic yards of excavation is reasonable.

323. The Owners also critique Mr. Lloyd's VMT cost estimate because of the methodology of crewing up the work instead of using a "process estimation" methodology. Process estimation determines the building materials necessary, then uses an estimating manual to determine the man-hours for each item.[521] It is a common way for engineers to cost projects.[522] But Mr. Ellwood indicated the approach that Pro Plus used was commonly used by contractors, and that process estimation on the VMT was problematic because it is a one of a kind, unique property.[523] On balance, this Court was not persuaded that Pro Plus's use of the crew-up method for estimating the cost of the VMT was unreasonable.

324. Pro Plus has estimated that the clearing and grading at the VMT would take 310 days.[524] But this Court found persuasive Hawk's observation that this crew needs to be "done and gone to make the terrain available for other crews."[525] And this Court concurred with Hawk's critique regarding the VMT camp. 450 days for VMT camp installation would appear excessive, while 78 workers at the camp, including 16 truck drivers and 24 laborers, as well as 28 pick-up trucks also appears excessive.[526] Yet it bears noting that Hawk's revised estimate for the direct costs for the VMT totaled $1.3 billion.[527] In contrast, Stantec's

---

[520] Tr. 4385-86 (Lloyd); MUN7-1535 to MUN7-1538.

[521] Tr. 3732-36 (Ellwood).

[522] Tr. 3732-33 (Ellwood).

[523] Tr. 3734-35 (Ellwood).

[524] MUN7-0008 at 544, 545.

[525] TO-07-0044.0008. *See also* Owners' Proposed Findings of Fact and Conclusions of Law ¶ 390.

[526] MUN7-0008 at 516, 555; TO-07-0044.0011.

[527] TO-07-0044.0021

cost estimate for the VMT was higher – at 1.693 billion – even though Stantec had fewer tanks and far less proposed excavation.[528]

ii. Indirect Costs, Including Contingency

325. "Indirect costs are percentages that might be applied to all or some portion of the direct costs."[529] The indirect costs applied by Pro Plus include (1) project and construction management, engineering, and inspection, (2) owners' costs, (3) ad valorem taxes and interest during construction, and (4) contingency. Each of these items is typically calculated as a percentage of direct costs associated with a project.

326. In 2006, the Division did not include any program manager costs in its RCN estimate.[530] In its 2006 assessment, SARB determined there should be a program manager profit of 3% of direct costs.[531] Beginning in 2008, SARB adopted a project management fee of 7.5% that included construction management, engineering, and inspection in addition to the project management fee.[532] The Pro Plus cost estimate for the 2006 tax year and adopted by this Court in the Amended Decision included an allowance of 7.5% of its direct costs for all project management costs.[533]

\\

\\

\\

\\

---

528 TO-07-0021.0013.

529 Tr. 3741 (Ellwood).

530 MUN7-0235 at 11.

531 Amended Decision ¶ 328.

532 Amended Decision ¶ 328; MUN7-238 at 18 ($701,220,443/$9,349,605,900 = 7.5%).

533 Amended Decision ¶ 333.

327. For tax years 2007 to 2009, Pro Plus again estimated program management costs at 7.5% of direct costs.[534] The Court again finds that a project management fee of 7.5% is appropriate.

328. In 2008, SARB reduced Pro Plus's estimation of owners' costs from 10% to 5%.[535] Mr. Ellwood, at the 2009 SARB hearing, testified why 10% was the appropriate allowance for these costs.[536] In 2009, the Board agreed 10% was appropriate, stating that "[t]he Board found particularly persuasive the testimony from the Municipalities' witnesses on the importance, in a project like the TAPS, of having personnel from the owners to shadow contractor personnel and closely monitor the ongoing construction work in order to limit delays and cost-overruns."[537]

329. In this Court's Amended Decision for the 2006 tax year, Pro Plus's proposed owners' costs of 10% of direct costs were likewise adopted.[538]

330. In these proceedings, Pro Plus continues to maintain that 10% of direct costs appropriately measures owners' costs.[539] The Court finds the percentages reasonable for the 2007 to 2009 tax years.

331. A replacement TAPS would be subject to ad valorem taxes during construction ("AVTDC").[540] In the 2006 tax year trial, the "Pro Plus team used Mr. Greeley's method of

---

[534] Tr. 3741 (Ellwood). Stantec similarly estimated engineering costs at 5% of direct construction costs for the main pipeline, and 12% for the pump stations and terminals. TO-07-0025.0684.

[535] MUN7-0236 at 15, 17.

[536] 2009 SARB Tr. 299-301 (Ellwood).

[537] MUN7-0236 at 20.

[538] Amended Decision ¶ 342.

[539] Tr. 3741-42 (Ellwood). Stantec used a figure of 9% for owners' costs. Tr. 3274 (Fiske); TO-07-0025.684.

[540] AS 43.56.060(e)(1); 15 AAC 56.110(b)(1).

calculating the ad valorem tax that had also been accepted by SARB."[541] The Court adopted that method as appropriate for determining the assessed value of TAPS for the 2006 tax year.[542]

332. In 2010, SARB determined that the Assessor's calculation required certain refinements to comply with Alaska law under 15 AAC 56.110(b)(1).[543]

333. In Alaska, the "full and true value" of an oil pipeline during construction is determined by the "actual cost incurred or accrued with respect to the property as of the date of assessment."[544] The regulation that implements this portion of the statute explains how certain costs should be taxable as incurred, such as construction machinery, while those that relate to the entire project should be prorated over the time taken to complete the entire project.[545]

334. Pro Plus's AVTDC computation provided a breakdown between the two categories of costs – those that the regulation requires be accrued and those that are taxable as incurred – for each tax year.[546] Based upon that breakdown, and applying the accrual schedule found in the example in 15 AAC 56.110(b)(1) over a seven year construction period, Pro Plus calculated the AVTDC at $657,521,600 for 2007, $721,816,800 for 2008, and $713,929,600 for 2009.[547] This Court finds that Pro Plus's method is consistent with the applicable regulation.

---

[541] Amended Decision ¶ 348 (internal citation omitted).

[542] Amended Decision ¶ 352.

[543] MUN7-0237 at 30-32.

[544] AS 43.56.060(e)(1).

[545] 15 AAC 56.110(b)1)

[546] MUN7-0008 at 39, 57, 588, 1119.

[547] MUN7-0008 at 56, 587, 1118.

335. For the 2006 tax year, the Court previously concluded that Pro Plus's methodology for the inclusion of interest during construction ("IDC"), calculated based upon a percentage of project spending spread over a seven-year period and assuming 100% debt financing at a cost of 6%, was appropriate for determining the assessed value of TAPS.[548] Consistent with that approach, Pro Plus's estimate for 2007, 2008 and 2009 included $1,949,285,100, $2,134,744,500, and $2,114,060 for IDC, respectively.[549] This Court finds that Pro Plus's method to calculate interest during construction is reasonable.

336. It is standard practice to include a contingency in a cost estimate to account for uncertainty about the actual cost. The Municipalities' expert Dr. Mark Cronshaw stated that the Association for the Advancement of Cost Engineering ("AACE") defines contingency as "an amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs."[550] The appropriate amount of contingency depends on the desired level of certainty that the actual cost of a project will not exceed the estimated cost.[551] As Dr. Cronshaw testified in the 2006 trial and again in these proceedings, a standard approach to determine contingency is the P50 or 50% level of confidence (i.e., the contingency amount that – when added to the base estimate – makes it equally likely that the project will actually cost more or less than the estimate).[552]

---

[548] Amended Decision ¶¶ 350, 352.

[549] MUN7-0008 at 55, 586, 1117.

[550] Tr. 4675 (Cronshaw).

[551] Tr. 4684-85 (Cronshaw).

[552] Tr. 4695; 4699-4700 (Cronshaw). *See also* Tr. 3637-38 (Allison); Amended Decision ¶ 353.

337. In the 2006 trial, the Court determined a 25% contingency was appropriate.[553] In 2007, the Department used an 8% contingency, which appears to have been adopted by SARB.[554] In 2008, the Division reduced Pro Plus's proposed contingency factor from 25% to 20%. On review to SARB, the Board concluded that the contingency factor should be no more than 5%.[555] In 2009, the Division used a 10% contingency factor, which the Board rejected as improper and instead employed a 25% contingency.[556] This was in response to the additional information provided to SARB by Dr. Cronshaw and the Pro Plus team, which SARB found constituted the "most persuasive" evidence before the Board.[557] SARB held "It was clear to the Board that based on their careful assessment of these risks, the 25% contingency factor in the 2009 Pro Plus cost study was justified."[558]

338. Dr. Cronshaw relied upon the AACE in preparing his opinion in this case. As explained by Dr. Cronshaw:

> AACE describes five classes of estimate. Class 5 is a preliminary cost estimate that has a very wide range because of substantial uncertainty. Class 1 is a control estimate that's usually prepared for financial control purposes during a project, so after the detailed engineering has been completed and so on. And class 3 is something between.[559]

A conceptual study would have a relatively high contingency because the detailed design basis, engineering, and permitting would not yet have occurred, while a budgetary estimate

[553] Amended Decision ¶ 366.

[554] MUN7-0234 at 12.

[555] MUN7-0235 at 18-20.

[556] MUN7-0236 at 18.

[557] MUN7-0236 at 19.

[558] MUN7-0236 at 19.

[559] Tr. 4719 (Cronshaw).

would employ a lower contingency if a detailed cost estimate had been prepared.[560] The Pro Plus team determined that the RCN project would appropriately be labeled somewhere between a Class 3 and a Class 4.[561]

339. The contingencies estimated by the parties in this case were substantially different. Experts for both the Municipalities (Dr. Mark Cronshaw) and the TAPS Owners (Mr. Jerald Allison) ran Monte Carlo analyses to model the uncertainty associated with the project to arrive at a contingency estimate for the TAPS RCN.

340. From his Monte Carlo analysis, Dr. Cronshaw concluded that contingencies of 36%, 39%, and 37% are the appropriate amounts for a P50 case for the Pro Plus study for years 2007, 2008, and 2009.[562]

341. The Court finds Dr. Cronshaw presented a comprehensive and well-documented contingency analysis consisting of extensive materials that were admitted into the record. He also carefully followed the recommended procedures of the AACE. Dr. Cronshaw verified the reasonableness of his Monte Carlo analysis by comparing his findings with the recommended AACE ranges.[563] Although the AACE ranges apply strictly only to process facilities, the fact that Dr. Cronshaw's analysis was within the ranges provides a check on the reasonableness of his conclusions.[564] Additionally, as discussed below, Dr.

---

[560] Tr. 4718-19 (Cronshaw).

[561] Tr. 4719 (Cronshaw).

[562] Tr. 4679; 6331 (Cronshaw).

[563] Tr. 4720 (Cronshaw).

[564] Tr. 4720 (Cronshaw).

Cronshaw verified his analysis by comparing the contingency with cost overruns from numerous actual projects, including TAPS' projects, further validating his results.[565]

342. Although Dr. Cronshaw determined a substantially higher contingency was appropriate, Pro Plus, based on the experience and consensus of the team, chose a 25% contingency.[566] Mr. Ellwood expressed his confidence in the number chosen by the Pro Plus team: "We think that's a very reasonable number. We have had many, many discussions amongst the team about what to do, and we have checked that number against what other corporations do; and we're all, I think, entirely comfortable with it. I know I am."[567] Dr. Cronshaw estimated that Pro Plus's use of a 25% contingency meant there would be at least an 84% chance that the actual cost of the project would exceed Pro Plus's final cost estimate.[568]

343. The contingency adopted by Stantec for its 30-inch hypothetical pipeline, as calculated by Mr. Allison through his Monte Carlo analysis, was 3.3%, 3.4%, and 3.5% for tax years 2007, 2008, and 2009, respectively.[569]

344. At a theoretical level it appears that a major difference between the Stantec contingency and the Pro Plus contingency is that Stantec concluded the project had little or no uncertainty due to it being an estimate to build a replacement for TAPS as of fixed dates in the past.[570] Stantec concluded that because much was known about TAPS today due to

---

[565] Tr. 4725-27 (Cronshaw); 6314-15 (Cronshaw).

[566] Tr. 3742 (Ellwood); 4680 (Cronshaw), 6331-32 (Cronshaw); 6496 (Tise).

[567] Tr. 3742 (Ellwood).

[568] Tr. 4680 (Cronshaw).

[569] Tr. 3607-08 (Allison); 4752 (Cronshaw); 5762 (Karlik).

[570] Tr. 5841-42 (Karlik).

it already having been constructed, there was minimal uncertainty in such items as the labor rates and the cost of obtaining such items as permits for construction, thus a contingency of approximately 3.5% was appropriate.[571] Yet the Stantec design is substantially different from the existing line with its smaller diameter, higher pressure line, single support VSMs and DRA with 80% drag reduction. Further, the Stantec design relies on freestanding thermosyphons and an extensive use of ice roads, both of which also differ from the original design and construction.[572] As Dr. Cronshaw concluded, "it seems curious to assert that the contingency for that different design [Stantec] would be much lower because one knows something about the existing 48" line."[573]

345. Mr. Allison's trial testimony on this topic conflicted with his deposition testimony.[574] At trial Mr. Allison was asked, "[T]he fact that this was a replacement cost new was not a significant part of the debate in terms of the elicitation, was it?"[575] Mr. Allison responded:

> No, as a matter of fact, I think – I don't think that's correct. I think we did talk about that this is a replacement cost new . . . we talked about that the fourth quadrant is considerably smaller for an RCN . . . I know we talked about it when we discussed the fourth quadrant.[576]

But counsel then repeated the identical question that had been asked to Mr. Allison at his deposition. There, Mr. Allison, reading from his deposition testimony at trial, stated: "The fact that it was a replacement project had no impact on how the elicitation was done and

[571] Tr. 5761-62 (Karlik); 5796 (Karlik); 5841-42 (Karlik).

[572] Tr. 4751 (Cronshaw).

[573] Tr. 4751 (Cronshaw).

[574] Tr. 3631-32 (Allison).

[575] Tr. 3627 (Allison).

[576] Tr. 3627-28 (Allison).

how the number was derived whatsoever . . . ."[577] On redirect, later at trial, counsel for the Owners asked Mr. Allison, "Did you explain, in your deposition, what you think the typical range of contingency is for a replacement cost estimate?"[578] Inexplicably, Mr. Allison responded: "My recollection is that I would have expected it to be less than what it would be for a normal construction process."[579] Mr. Allison did not attempt to explain why his deposition testimony directly contradicted his testimony at trial.

346. An additional example of Mr. Allison's unreliability as a witness was evidenced when he testified regarding a typical range for contingency. On direct he was asked, "Do you have in mind the typical range of contingency that you would expect for a replacement cost new estimate?"[580] Mr. Allison responded: "Probably somewhere between 2 and 5 percent . . . ."[581] But on cross, counsel read a similar question asked of Mr. Allison during his deposition: "What would you think the typical range of contingency is for a replacement cost estimate in a study of the level and detail of the Stantec study?"[582] Mr. Allison testified at his deposition (as read at trial): "My answer is: I don't have an opinion on a range of percentage estimate that would be correct, right, typical, or anything else for a replacement project because I've never done comparative studies and I've never read – anybody that did comparative studies."[583]

---

[577] Tr. 3631-32 (Allison).

[578] Tr. 3657 (Allison).

[579] Tr. 3657 (Allison).

[580] Tr. 3657 (Allison).

[581] Tr. 3657 (Allison).

[582] Tr. 3660 (Allison).

[583] Tr. 3660 (Allison).

347. Because of his inconsistent sworn statements, this Court finds Mr. Allison was not a credible witness. Rather, this Court concurs with Dr. Cronshaw's observation that Stantec's contingency was unreasonably low, particularly for a project at the conceptual stage only.[584]

348. Carlton Karlik also testified for the Owners about the appropriate contingency to be used in a TAPS RCN analysis. He testified that with an RCN, there is much less unknown about a project than a Greenfield original construction project, thus less risk is involved, and hence a lower contingency is appropriate.[585] However, Mr. Hisey testifying for the Municipalities asserted that even a completed project carries a contingency of 2% to 3% to account for remaining unknowns such as startup, completion and potential litigation costs.[586] To that end, Mr. Hisey testified that he has reviewed hundreds, if not thousands, of Alyeska funding authorizations ("AFEs"), and he has never seen a construction AFE with a contingency in the 3% to 4% range.[587]

349. Moreover, Charles Coulson, the President of BP Pipelines (Alaska) testified at his deposition in this case that he was unsure of the standard contingency for TAPS projects.[588] But before FERC, Mr. Coulson testified that a 30% contingency at the outset of a project would be "normal." Before FERC he also testified, "When you get down to the

---

[584] Tr. 4253 (Cronshaw).

[585] Tr. 5759-62, 5840-41 (Karlik).

[586] Tr. 4980 (Hisey).

[587] Tr. 4978 (Hisey).

[588] MUN7-0001 at 3879.

execute phase of a particular project, where the engineering design is completed, you'd expect the contingency to be much lower, five or ten percent in some cases."[589]

350. As in the 2006 tax year trial, Mr. Karlik did not determine a specific contingency.[590] Instead he testified for the Owners that a range of 5% to 10% contingency was typical when doing a replacement cost new estimate (versus an original construction estimate).[591] But based on the totality of evidence presented on contingency, the Court again finds Mr. Karlik's testimony unpersuasive.[592]

351. Dr. Cronshaw thoroughly validated the reasonableness of the Pro Plus team's 25% contingency. In addition to performing his Monte Carlo analysis and comparing the range of his calculations to the AACE literature (as discussed above), he looked at cost overruns experienced by other megaprojects and at TAPS' specific projects.

352. Dr. Cronshaw testified regarding the MacKenzie Valley Project. In 2004, the project presented its cost estimate to the National Energy Board in Canada of $3.8 billion, with a 28% contingency.[593] By 2005, after project expenditures of $600 million,[594] the estimate had grown to $7.8 billion, nearly doubling the estimate from the previous year.[595]

353. Additional examples offered by Dr. Cronshaw in support of his opinion included the Nord Stream Pipeline in the Baltic Sea.[596] There, the cost estimate was €5 billion in

[589] MUN7-0001 at 3879-80.

[590] Amended Decision ¶ 358.

[591] Tr. 5762 (Karlik); 4750 (Cronshaw).

[592] Amended Decision ¶ 358.

[593] Tr. 4725 (Cronshaw) (the figure includes a 5% risk allowance).

[594] Tr. 6317-18 (Cronshaw).

[595] MUN7-0010 at 44; Tr. 4723-24 (Cronshaw).

[596] MUN7-0010 at 44, Tr. 4726 (Cronshaw).

2005, rising nearly 50% to €7.4 billion in 2008.[597] Another example was the BTC pipeline from Azerbaijan to Turkey which was reported to have an expected 30% cost growth from its original estimate to nearly $3 billion.[598] While some of the cost overruns in the above mentioned projects may be attributable to changes in scope, overall these examples supported Dr. Cronshaw's opinion that historically, large-scale projects experience notable cost growth.

354. Regarding the Denali Gasline, after $135 million had been invested to develop a cost estimate, Mr. Coulson indicated the contingency for the project was "in the neighborhood of 30%."[599]

355. Dr. Cronshaw persuasively opined that TAPS' own projects also support a 25% contingency as the minimum appropriate contingency to achieve a proper assessed valuation of TAPS. Dr. Cronshaw referred to an Aerospace Corporation report dated July 1977 which indicated that as of mid-1974, the expected cost to complete TAPS was $4.088 billion.[600] By that point, significant components of the project were already in place: the pipe had been purchased, haul roads had been constructed, project labor agreements had been signed, the Federal "Alaska Pipeline Act" had been passed, contractors such as Bechtel and Fluor had been retained, and other key contracts had been assigned.[601] Three years later, in 1977, the actual project cost was $7.815 billion – nearly double the 1974 estimate.[602]

---

[597] MUN7-0010 at 44; Tr. 4726 (Cronshaw).

[598] MUN7-0010 at 44; Tr. 4727 (Cronshaw).

[599] Coulson Dep. 167-68; MUN7-0001 at 3877.

[600] MUN7-1151 at 12. The original estimate from 1969 indicated in that exhibit was under $1 billion.

[601] MUN7-2554 at 47-48; Tr. 4731 (Cronshaw).

[602] Tr. 4731 (Cronshaw).

356. Another real-world example supporting a contingency substantially higher than that offered by the Owners relates to SR. As part of discovery, the Owners provided certain AFEs related to the Owners' budgetary approval of SR of TAPS. In March 2004, the Owners authorized SR in the amount of $233 million (after $10 million had already been spent on engineering).[603] In 2005, Alyeska prepared supplemental AFEs seeking approval of an additional $168.2 million to complete SR.[604] Then, in 2007, Alyeska submitted supplemental AFEs for additional expenditures that raised the cost of completing SR to $696 million, or about a 185% cost overrun.[605] Moreover, the 2007 supplemental AFE included an 18.5% contingency – after much of the SR had already been completed and substantial cost overruns already incurred.[606] In reviewing the AFEs, Dr. Cronshaw also noted that the extensive cost overruns were not attributable to a change in scope but rather design development issues.[607]

357. Dr. Cronshaw also referred to a 2005 Fluor Cost Study to support his opinion that a 25% contingency is reasonable. The study was prepared for the Owners for FERC ratemaking proceedings to set out the cost for the dismantling and removal of TAPS. The 2005 Fluor updated cost estimate included a 25% contingency which Fluor stated: "is consistent with the contingency factor used in the 1983 estimate."[608] Alyeska later prepared

---

[603] Tr. 4733 (Cronshaw).

[604] Tr. 4734 (Cronshaw).

[605] Tr. 4737 (Cronshaw).

[606] Tr. 4737 (Cronshaw); MUN7-0011 at 2-3.

[607] Tr. 4735 (Cronshaw).

[608] MUN7-2569 at 4; Tr. 4739-40 (Cronshaw).

a 2007 update to the Fluor study which also used a 25% contingency for all but a few cost categories (e.g., the contingency for the VMT was 22%).[609]

358. A 2010 study of the cost of heaters to operate TAPS at declining throughput levels prepared by Larkspur Associates, LLC ("Larkspur") for BP Pipelines also validates a contingency of no less than 25%. The study was a detailed estimate of the cost of all the heater facilities by location along the pipeline that may be necessary to operate TAPS down to 100,000 bbl/d. As to contingency, the report stated,

> The conceptual estimates include contingency at 40 percent based on an accuracy range of +35% / -20% as reviewed and determined based on AACE published documentation (see attached). Based on the process information and quantities presented, estimate approach and experience of the project team we recognize that there has been very little design work done to date to reflect a lower percentage or a tighter accuracy range.[610]

359. Larkspur further supported its 40% contingency by noting that although the project was in an early stage, there was a significant amount of known cost information: "Based on the approach used in developing the costs which are based on a significant amount of historical project information and current actual cost information we believe the estimates are between a Class 3 – 4 as published by AACE."[611] The Pro Plus team also considered its TAPS' RCN a Class 3 to 4 project, yet utilized a lesser contingency of 25%.[612]

360. The Larkspur study also points out that, "Several sites (MP 31, MP 39, MP 75, MP 178, MP 211, MP 629) not currently corresponding to an existing pump station or

---

[609] MUN7-2568 at 17; Tr. 4740-41 (Cronshaw).

[610] MUN7-3044 at 19.

[611] MUN7-3044 at 19.

[612] Tr. 4717-19 (Cronshaw).

developed site location are required . . . ."[613] The study specifically refers to those sites as "Greenfield."[614] But where heater facilities are costed for installation at existing sites the study calls them "Brownfield."[615] Yet for both Greenfield and Brownfield locations, Larkspur uses the same 40% contingency.[616] This is at odds with Mr. Karlik's unsupported assertion that "RCN estimates require less contingency than Greenfield new ventures."[617]

361. These validations, in addition to Dr. Cronshaw's rigorous Monte Carlo modeling and associated analysis, fully persuade the Court that the 25% contingency employed by Pro Plus is reasonable for a RCN of TAPS. Further, based upon the evidence presented at the trial de novo, the Court finds that a contingency of less than 25% would result in an improper valuation of TAPS for the three years at issue.

4. Conclusion of the RCN of TAPS

362. Both the Owners and the Municipalities submitted extensive cost studies and provided detailed testimony regarding each of the proposed replacement TAPS.

363. For the reasons set forth above, this Court has concluded that the Stantec pipeline is not an appropriate design to use as the basis for the application of the cost approach in the valuation of TAPS.

364. Overall, the Pro Plus RCN is an appropriate RCN to use as the basis for the application of the cost approach. Throughout this litigation, Pro Plus experts have strived to

---

[613] MUN7-3044 at 4.

[614] MUN7-3044 at 7-10, 13.

[615] MUN7-3044 at 9.

[616] *See, e.g.*, MUN7-3044 at 8 and 38 (MP 39 Greenfield at 40%) *versus* MUN7-3044 at 9 and 49 (PS 3 Brownfield also at 40%).

[617] TO-07-0046 at 2.

thoroughly answer questions posed by the Court and on cross-examination.[618] Conversely, the Stantec experts were unable to answer numerous questions about the details of their cost estimate on cross-examination.[619]

365. Overall, this Court finds that the Pro Plus cost estimates are reliable. However, as set forth above, this Court has identified several concerns with the Pro Plus cost estimates. It is neither necessary nor feasible to make a precise adjustment in the Pro Plus RCNs to account for each of these concerns – the goal of an RCN, in any event, is to arrive at an estimate of the cost of replacing TAPS with a modern day equivalent of similar quality and like utility – not a precise amount. But this Court does find that some adjustment to the Pro Plus RCN is warranted to account for the concerns that have been identified in the preceding findings. Based upon this Court's consideration of all the evidence, the Court finds that a 10% reduction in Pro Plus's RCN cost estimates for each of the lien years is warranted to arrive at amounts that this Court has determined would better reflect the estimated cost to replace TAPS in each of the lien years with a new pipeline transportation system of similar quality and like utility.

366. The Owners asserted that the RCNs should be compared to the cost estimates that were prepared for the Denali pipeline and Trans Canada gas pipeline project. But due to confidentiality restrictions, no witness was able to provide detailed testimony to this Court about either of those cost estimates. As a result, this Court did not accord weight to either of

---

[618] *See, e.g.*, Tr. 3725-26, 3737-38, 3742, 3764-65, 3777-78, 3858-59, 3870, 3949, 6698-99 (Ellwood); Tr. 4440, 4461, 4471, 4473-74, 4484-85, 4511-13, 4516-17, 4632-33, 6612 (Steindorff); Tr. 4954-55, 4961-64, 4968, 4979, 4983, 5060, 6368 (Hisey) (sealed); Tr. 3898-4057 (Ellwood); Tr. 4178-4245 (Tise); Tr. 4394-4424 (Lloyd); Tr. 4518-74, 4608-31 (Steindorff).

[619] *See, e.g.*, Tr. 3314-15, 3327-28, 3329-30, 3331-32, 3330, 3337-38, 3341-42, 3359, 3363-64 (Fiske); Tr. 2511-16, 2516-18, 2520-22, 2532-33, 2538, 2541, 2542, 2543 (Rein).

those cost estimates, while recognizing that, had confidentiality issues been addressed, the information in those estimates could have been quite helpful for comparison purposes.

367. The 2007, 2008 and 2009 RCN cost estimates advanced by Pro Plus were $19.606 billion for 2007, $21.471 billion for 2008, and $21.263 billion for 2009. Reducing each of these amounts by 10% results in the following determinations by this Court of the Replacement Cost New for TAPS for each of the tax years at issue:

2007	$17.645 billion
2008	$19.324 billion
2009	$19.137 billion

B. Depreciation

1. Methods of Calculating Depreciation

368. Once the RCN is determined, the appraisal analysis requires a calculation of the amount of depreciation. "Depreciation is the difference between the contributory value of an improvement and its cost at the time of appraisal."[620] The three types of depreciation traditionally recognized by appraisers are physical deterioration, functional obsolescence, and economic obsolescence.[621] The traditional definitions of these terms are:

> *Physical deterioration* is the loss in value or usefulness of a property due to the using up or expiration of its useful life caused by wear and tear, deterioration, exposure to various elements, physical stresses, and similar factors.
>
> *Functional obsolescence* is the loss in value or usefulness of a property caused by inefficiencies or inadequacies of the property itself, when compared to a more efficient or less costly replacement property that new technology has developed.

[620] *The Appraisal of Real Estate* at 391.

[621] *Valuing Machinery and Equipment* at 43; *The Appraisal of Real Estate* at 391-92; Tr. 11251-52 (Podwalny).

> *Economic obsolescence* (sometimes called "external obsolescence") is the loss of value of a property by factors external to the property. These may include such things as the economics of the industry; availability of financing; loss of material and/or labor sources; passage of new legislation; changes in ordinances; increased cost of raw materials, labor, or utilities (without an offsetting increase in product price); reduced demand for the product; increased competition; inflation or high interest rates; or similar factors.[622]

369. The three principal methods for estimating depreciation are: (1) the market extraction method; (2) the economic age-life method; and (3) the breakdown method.[623] The market extraction method and the economic age-life method are the primary methods used by most appraisers to estimate the total depreciation in a property; each is "applied to the whole property and are easier to understand and use."[624]

370. In its simplest form, the economic age-life method considers all three forms of depreciation using a single calculation.

371. The market extraction method relies upon the availability of comparable sales from which depreciation can be extracted.[625] In the case of TAPS, direct comparable sales information is not available, so that method is not appropriate.[626]

372. The breakdown method of depreciation calculates each form of depreciation (physical, functional, and economic) separately.[627] The breakdown method "is primarily used when the appraisal assignment requires that each form of depreciation be accounted

---

[622] *Valuing Machinery and Equipment* at 67. *See also The Appraisal of Real Estate* at 391-92; Amended Decision ¶ 378.

[623] *The Appraisal of Real Estate* at 409.

[624] *The Appraisal of Real Estate* at 409.

[625] *The Appraisal of Real Estate* at 416.

[626] Tr. 12349 (Connolly).

[627] *The Appraisal of Real Estate* at 424.

for in the appraisal report,"[628] and is "used when the market extraction and economic age-life methods cannot be applied."[629] The Owners' appraiser Michael Remsha used this method.

373. The Court was not persuaded by Mr. Remsha's application of the breakdown method to depreciate TAPS. Mr. Remsha opined that TAPS was 60% physically depreciated each of the tax years at issue.[630] As part of his calculation, and despite new SR pumps being installed during the lien years, he concluded that the weighted chronological age of TAPS' pumps was 29 years, and that their entire service life was 35 years – such that the newly installed pumps had only 6 years of life remaining by his calculations during each of the three lien years.[631] Given the recent $700 million in SR investment, Mr. Remsha's determinations in this regard were not credible.

374. Mr. Remsha also quantified an inutility penalty for TAPS based upon a projection of future inutility of the 30-inch Stantec pipeline.[632] But during the lien years, the 30-inch Stantec pipeline would be operating well over any reasonable maximum capacity for a 30-inch pipeline such that use of a future projection of unused capacity based on the maximum design capacity that Stantec asserted for its 30-inch pipeline is unwarranted. Moreover, the 30-inch pipeline is quite different from TAPS and may not reasonably be used as a standard to determine TAPS' depreciation.

375. Another concern with Mr. Remsha's approach is that with his breakdown method, TAPS is worth more when he assumed it could no longer transport oil below a

---

[628] *The Appraisal of Real Estate* at 425.

[629] *The Appraisal of Real Estate* at 425.

[630] TO-07-0004.0253.

[631] TO-07-0004.0253.

[632] TO-07-0004.0079-88 (projected future inutility used as a basis for deduction from the current economic value of TAPS).

300,000 bbl/d throughput than it would be worth if it could transport oil down to 200,000 bbl/d.[633] This illogical result indicates a major flaw in Mr. Remsha's depreciation methodology.

376. For the foregoing reasons, this Court did not apply the breakdown method to depreciate TAPS.

377. In addition to the standard depreciation approaches, this Court also considered the use of a units-of-production method to depreciate TAPS. This method is more typically employed in depreciation for accounting purposes, not appraisal depreciation.[634] "This method places emphasis on the total units to be produced and the rate of production. It takes into consideration the service life of an asset and thereby permits exhaustion of natural resources to be taken into account."[635] The units-of-production approach has also been termed "the life-of-the-reserves" depreciation methodology because the valuation is "based on the estimated reserves of the system rather than the calendar years that those reserves are estimated to be in production."[636]

378. The Municipalities assert that "unit-of-production depreciation would not consider reserves growth and tend to overstate depreciation."[637] Yet the applicable statute directs valuation "based on the estimated life of the proven reserves of gas and unrefined oil

[633] *See* TO-07-0004.0249. Indicated value was $2.2 billion with 200,000 bbl/d mechanical throughput limitation, and $2.3 billion with 300,000 bbl/d mechanical throughput limitation.

[634] *Valuing Machinery and Equipment* at 406.

[635] *South Dakota Public Utilities Commission v. Federal Energy Regulatory Commission*, 668 F. 2d 333, 335, n.2 (8th Cir. 1982).

[636] *Natural Gas Clearinghouse v. Fed. Energy Regulatory Comm'n*, 965 F. 2d 1066, 1070 n.5 (D.C. Cir. 1992).

[637] Municipalities' Proposed Findings of Fact and Conclusions of Law ¶ 611.

then technically, economically, and legally deliverable into the transportation facility"[638] – not valuation based on future oil and gas that may become proven reserves at some time in the future, but are not proven reserves as of the valuation date. Particularly where this Court has determined that the RCN should include the full utility of the TAPS' 48-inch pipeline's ability to transport up to 2.1 million bbl/d, the units-of-production approach might better capture the full degree of obsolescence that the property currently has by incorporating the proven reserves as of the lien dates into the valuation more precisely than the economic age-life method.

379. Roger Marks noted that the units-of-production approach had been used under the TAPS Settlement Methodology for TAPS' tariffs for many years, and that under that methodology the original rate base was fully depreciated by the end of the 1990s.[639] In his view, extending TAPS' economic life for additional decades on a straight line basis using the economic age-life method would effectively take "most of those previously depreciated costs and deem . . . them un-depreciated again, which again, reduces the RCN adjustment and increases the ad valorem tax."[640] This argument was not persuasive to the Court, as the "value" of the asset for rate-making purposes is not related to its "full and true value" as defined by AS 43.56.060(e) for ad valorem tax purposes.[641] This Court was more persuaded by Mr. Marks' additional argument that "depreciation depicts . . . the decline of the service potential... and the argument for units of production economically is that . . . for an asset like a pipeline, it more accurately mirrors...how the asset was used over its

[638] AS 43.56.060(e)(2)

[639] Tr. 12127, 12147 (Marks).

[640] Tr. 12147 (Marks).

[641] *See also* Municipalities' Proposed Findings of Fact and Conclusions of Law ¶ 603.

life . . . ."[642] Thus, the approach recognizes that the economic value of TAPS was considerably higher in 1988, when the average daily throughput was over 2 million bbl/d,[643] than it will be in 2070, when the Municipalities estimate that total ANS production of current proven reserves will be less than 100,000 bbl/d.

380. Under a units-of-production approach, in the event that additional reserves are proven on the ANS in the future, then the value of TAPS for ad valorem tax purposes would increase based upon those additional reserves.

381. This Court finds that the legislative history, while inconclusive, indicates that the Legislature was aware of the units-of-production approach and did not specifically reject it when valuing pipeline property for ad valorem tax purposes. For example, at an October 1973 House Finance committee meeting, Homer Burrell addressed each of the sections of HB1. His description of the depreciation method for pipeline property appears to be a units-of-production approach:

> Pipeline and pipeline equipment. [It] is depreciated on the economic life except in the event the physical life is different. Taking a $4 billion installation as the cost with production high in the initial years, it would decrease rather steeply and then level off as production levels off. It will depreciate to probably half value during the first ten years, and is to the oil companies' advantage. However, if more oil is discovered (assuming the pipeline has an unlimited physical life) the line would again increase and flatten out, depending on how much oil is discovered.[644]

[642] Tr. 12151 (Marks).

[643] TO-07-0004.0027.

[644] *Minutes* at 50, H. Finance Comm., 8th Leg., 1st Spec. Sess. (Oct. 22, 1973) [2007 R. 9736]. In an ensuing paragraph of the minutes, Mr. Burrell is quoted as stating "the pipeline is not depreciated on units of production but on straight line." From the context of that statement, however, it appears that he was referring there to the use of straight line depreciation that is explicitly referenced in the second portion of the statute that would apply only in the event that "too much line is built and oil is depleted" – i.e., "when the production rate is low." *Id.* at 9736. *Cf.* Municipalities' Proposed Finding ¶ 606.

382. AS 43.56.060(e)(2) explicitly directs the use of "straight line depreciation" only for those pipelines that have an economic life that is materially shorter than the estimated physical life. Arguably, this demonstrates that the Legislature was well aware of the concept of straight line depreciation and decided not to mandate its use for pipelines in operation such as TAPS.

383. The total barrels of oil transported on TAPS from the date of the pipeline's inception up to each of the lien dates was as follows:[645]

January 1, 2007:	15,278,153,140
January 1, 2008:	15,548,315,190
January 1, 2009:	15,805,814,856

384. Based on this Court's conclusion that the proven reserves on the ANS are between 7 and 8 billion barrels during the lien years, as discussed herein, a units-of-production deprecation methodology would result in a determination that TAPS was currently approximately two-thirds depreciated during the lien years.

385. While this Court has given careful consideration to a units-of-production approach, this Court finds that the Division and SARB should be accorded the first opportunity to consider its potential applicability to the depreciation of TAPS. The approach is not necessarily a standard appraisal methodology.[646] And it is clear that the economic age-life analysis applied by the Division and the Board during each of the lien years is a standard methodology. Stated differently, this Court does not find that the Board's lack of

[645] TO-07-0004 at 260, 338, 408.

[646] *See* 15 AAC 56.110(c).

reliance on a units-of-production deprecation methodology constituted a fundamentally wrong principle of valuation.

386. The economic age-life method was used by the Division and SARB for the lien years at issue, with additional depreciation deductions for functional and external obsolescence.[647] The Court also applied a modified economic age-life method for the 2006 lien year.[648]

387. In the economic age-life method, depreciation is estimated by calculating the ratio between the effective age of the property and its economic life expectancy using the following formula:

[Effective Age / Total Economic Life] x Total Cost = Depreciation.[649]

388. Economic useful life is the "estimated period of time that a new property may be profitably used for the purpose for which it was intended."[650] In estimating a property's economic life, "[a]ll aspects of a property and its market, including the quality and condition of the construction, the functional utility of the improvements, and market and locational externalities must be considered."[651] "An improvement's total economic life begins when it is built and ends when the improvement no longer contributes value for the use to which it was originally intended and is no longer the highest and best use of the underlying land."[652]

---

647 MUN7-0234 at 6.

648 Amended Decision ¶¶ 386, 421.

649 *The Appraisal of Real Estate* at 420; *Valuing Machinery and Equipment* at 81-82. *See also* Amended Decision ¶ 380.

650 *Valuing Machinery and Equipment* at 565.

651 *The Appraisal of Real Estate* at 413.

652 *The Appraisal of Real Estate* at 412.

389. In the case of TAPS, AS 43.56.060(e)(2) requires the Court to determine its economic value based upon the estimated life of the proven reserves that are then technically, economically, and legally deliverable into the pipeline as of the lien date. Thus, under the statute, these proven reserves serve as a proxy for the economic life of the pipeline for ad valorem tax purposes.

390. The economic age-life method is "limited in that [it] typically reflect[s] a straight line pattern of depreciation."[653] As explained in *The Appraisal of Real Estate*, "this method assumes that every building depreciates on a straight-line basis over the course of its economic life. The straight-line pattern is only an approximation of the total depreciation of a property at a specific point in time."[654]

391. The economic age-life method requires a determination of the "life of the line" – meaning the precise year in the future that TAPS will no longer transport proven reserves. Without a scaling adjustment, the approach can lead to an overestimation of the value of pipeline property that transports declining proven reserves. By way of example, the Municipalities' appraiser Mr. Podwalny assumed that TAPS' economic end-of-life on January 1, 2007 would be December 31, 2067.[655] Based on that assumption, and using the Pro Plus RCN, he determined that the value of TAPS was $12.893 billion as of that lien date.[656] But in their proposed Findings, the Municipalities advocate an end-of-life date for TAPS of 2075 – eight years later than Mr. Podwalny had assumed.[657] Making just that one change adjusts

[653] *The Appraisal of Real Estate* at 421.

[654] *The Appraisal of Real Estate* at 421.

[655] MUN07-0035 at 28.

[656] MUN07-0035 at 51.

[657] Municipalities' Proposed Findings of Fact and Conclusions of Law ¶ 893.

the value of TAPS to $13.689 billion – an increase of nearly $800 million– or approximately 6% – over Mr. Podwalny's valuation based solely on this eight year adjustment over 50 years off into the future. In the Court's view, this demonstrates that an exclusive reliance on straight-line economic age-life depreciation without scaling does not accord "due regard to the economic value of the property based on the estimated life of the proven reserves."[658] This is particularly true when it is undisputed that oil reservoirs typically have long tails of production, meaning that their production typically falls off fairly sharply after several years and then continues at a relatively low rate of production for many, many years thereafter.

392. This Court finds that SARB's reliance on the economic age-life method with appropriate modifications to include all functional and external obsolescence was not the application of a fundamentally wrong principle of valuation. Further, application of that methodology has been fully supported by the extensive evidence presented to this Court at the trial de novo.

2. Life of the Line

393. Application of the economic age-life method to depreciate TAPS requires a determination of TAPS' minimum throughput capacity, as well as a determination of the estimated life of the remaining proven reserves on the ANS.

a. Minimum Throughput Capacity

394. AS 43.56.060(e)(2) requires the Court to consider the estimated life of proven reserves "technically, economically, and legally deliverable *into* the transportation facility." (emphasis added) The statute does not expressly require the Court to consider the

[658] AS 43.56.060(e)(2).

transportation facility's hydraulic, mechanical, or operational capacity to transport all of those proven reserves.

395. The Municipalities argue that consideration of the pipeline's ability to transport all of those reserves that are deliverable is "an exhaustive and unnecessary exercise."[659] They also assert that the Legislature's use of proven reserves as the proxy for the economic life of TAPS tends to understate the actual economic life of TAPS, and that to impose an additional minimum throughput limit would compound this understatement of the pipeline's actual economic life. The Municipalities also assert that common sense and expert testimony demonstrate no otherwise economic pipeline has shut down at 100,000 bbl/d, 50,000 bbl/d, or below.[660] At trial, many expert witnesses testified they were unaware of any pipeline that had suspended transportation service for oil that was otherwise economic to produce due to mechanical, hydraulic or operational limitations of the pipeline.[661]

396. Randy Hoffbeck, the former Assessor, testified that TAPS has been the only pipeline in Alaska that has been assessed using a minimum throughput capacity determination.[662] All other pipelines use the economic life of the proven reserves to determine the pipeline's value, without regard to the hydraulic, mechanical, or operational characteristics of the pipeline.[663]

---

[659] Municipalities' Proposed Findings of Fact and Conclusions of Law at ¶ 613.

[660] Tr. 5130-31 (Riordan); Tr. 8266-68 (Cicchetti); Tr. 11895 (Remsha).

[661] Tr. 674, 11895 (Remsha); Tr. 5130-31 (Riordan); Tr. 8266-68 (quoting Coulson Dep.); Tr. 9218 (Malvick); Tr. 11090 (McDevitt).

[662] Tr. 11565 (Hoffbeck).

[663] Tr. 11565 (Hoffbeck).

397. The Assessor has interpreted the statute to require a minimum throughput determination.[664] In this regard, the Assessor testified that "the idea is that it is not a reserve that can't get transported to market and it won't get delivered to the facility if the facility can't transport it as of the lien date."[665] The Owners concur that a determination should be made as to TAPS' minimum throughput capacity for ad valorem tax purposes.[666] SARB has adopted this approach during each of the lien years.

398. This Court finds that SARB's interpretation of the statute to require a minimum throughput determination is reasonable and will be applied by this Court. There is likely a minimum throughput level at which point crude oil will no longer be transportable on TAPS. Thus, an owner of a pipeline may seek to demonstrate by a preponderance of the evidence that there is a specified minimum throughput limit that impacts the amount of proven reserves that are technically deliverable into the pipeline as of the lien date.

399. In 2006, the Assessor determined that the minimum throughput of TAPS was 200,000 bbl/d or less, which the Board adopted for subsequent tax years and this Court also adopted in its Amended Decision for the 2006 tax year.[667]

400. At the trial for the 2007 through 2009 tax years, the Assessor advanced 150,000 bbl/d as TAPS' minimum throughput.[668] The Owners have asserted that TAPS will be unable to transport oil "when TAPS throughput at Pump Station 1 reaches between

[664] *See, e.g.*, MUN7-0236 at 23-24.

[665] Tr. 8716-17 (Greeley).

[666] *See, e.g.*, Owners' Proposed Findings of Fact and Conclusions of Law ¶¶ 422-543.

[667] MUN7-0233 to MUN7-0238; Amended Decision ¶¶ 389 – 390.

[668] Tr. 8717-20 (Greeley).

350,000 and 300,000 barrels per day."[669] The Municipalities have asserted that if a minimum throughput limitation is applied, that "more likely than not, TAPS will operate at least until flow becomes laminar (non-turbulent) at 40,000 to 50,000 bbl/d."[670]

401. The Municipalities' expert Dr. Jerry Modisette testified that there is no hydraulic or mechanical minimum throughput limit because the pipeline will be within pressure constraints at flows down to zero and the pump rate can also go down to zero through reducing pumps, throttling, and recirculation.[671] Former Alyeska Chief Operating Officer Dan Hisey concurred that there is no hydraulic or mechanical minimum throughput limit on TAPS.[672] The Owners' expert, Ulli Pietsch, also testified that there is no hydraulic or mechanical reason that TAPS cannot operate down to 50,000 bbl/d.[673] The inquiry therefore turns to whether there is an operational constraint that would prevent TAPS from transporting oil at some minimum capacity limit.

402. When an upstream oil production company books its proven reserves to the Securities Exchange Commission ("SEC"), it needs to perform an economic analysis to determine the financial feasibility of bringing the oil to market. One determinant in this process is the projected tariff rate to transport the oil on TAPS. In making that determination, an upstream ANS producer needs to make an assumption about TAPS' minimum throughput capacity so that the cost of transportation per barrel can be computed. The effect of a lower throughput capacity increases the total amount of proven reserves

---

[669] Owners' Proposed Findings of Fact and Conclusions of Law ¶ 535.

[670] Municipalities' Proposed Findings of Fact and Conclusions of Law ¶ 617.

[671] Tr. 9007-12 (Modisette).

[672] Tr. 8825-26 (Hisey).

[673] Tr. 2024-25 (Pietsch).

expected to be transported through TAPS, thereby decreasing the tariff on a per-barrel basis and extending the economic life of the oil fields.

403. Until approximately 2004, BP used 300,000 bbl/d as the minimum throughput capacity of TAPS for purposes of booking its Alaska North Slope SEC reserves.[674] At that point, BP began to consider whether the new variable speed pumps and recirculation piping associated with SR would permit the adoption of a substantially lower limit (and thus the booking of more reserves).

404. BPPA analyst John Haines testified at the trial in this case. In an email dated November 5, 2004, Mr. Haines stated:

> Momentum is starting to grow around booking more reserves based on an updated view of TAPS' minimum achievable rates . . . Lastly, when TAPS rates reach 100 MBD [100,000 bbl/d] we stop. Our consultant thinks we can probably operate TAPS below this minimum rate, but we didn't want to push it any further at this time.[675]

405. **[CONFIDENTIAL – SEE SEALED ENVELOPE.]** [redacted]

[redacted]

674 MUN7-4406; MUN7-3046 at 1.

675 MUN7-9094 at 1, 2 (confidentiality waived on record at Tr. 11421).

[redacted]

406. In 2004, BP Pipelines retained JTG Technology Consortium to conduct a study to revisit the minimum throughput limit on TAPS. The 308-page JTG report was completed in 2005 ("JTG Study") and concluded that "the low flow limit of the existing 48-inch TAPS pipeline was determined to be a PS [Pump Station] 1 rate of 135 MB/day [135,000 bbl/d]."[677]

407. The 135,000 bbl/d minimum throughput level set forth in the 2005 JTG Study was to be achieved with the addition of heat, although the study also allowed for other necessary modifications such as additional booster pumps, scraper trap valves, and piping for pigging.[678] Ulli Pietsch, the Owners' hydraulics expert in this trial, conducted the pressure and temperature simulations for the JTG Study.[679]

408. BPPA and its affiliates relied upon the JTG Study's conclusion of a 135,000 bbl/d low-flow limit to create tariff profiles that BP then used to report its reserves for several years to the SEC.[680]

[redacted]

677 MUN7-3000 at 6.

678 MUN7-3000 at 33, 75, 80.

679 Tr. 2043-44, 2046 (Pietsch).

680 Tr. 11413-17 (Haines).

409. In its initial year-end 2004 reserves submission to the BP London office, which was scheduled a couple of months before the JTG Study was concluded, BP Exploration and BP Pipelines personnel determined "an effective TAPS minimum throughput level of 150,000 bbl/d at 2053," using "conservative assumptions."[681] The report added:

> In the case of GPB [Greater Prudhoe Bay] and KRU [Kuparuk River Unit] (the biggest contributors to the reserves adds) each of these fields were still cash flow positive at 2064 (end of our tariff profile). The reserves coordinators arbitrarily chose to cut-off life at the earlier dates (2053 for GPB and 2047 for GKA) just to give themselves some future cushion.[682]

410. The JTG Study contained an alternative rail option that envisioned building a $3 billion 20-inch replacement pipeline from the North Slope to Fairbanks, and then using rail to transport the oil from Fairbanks to tidewater. That approach would allow reserves to be booked down to 45,000 bbl/d, if justified by high oil prices.[683]

411. **[CONFIDENTIAL – SEE SEALED ENVELOPE.]** [redacted]

---

[681] MUN7-9094 at 8.

[682] MUN7-9094 at 8 (confidentiality waived on record at Tr. 11425).

[683] Tr. 11411 (Haines); MUN7-3046 at 1.

[redacted]

412. BP Pipelines failed to provide the 2005 JTG Study in discovery for the 2006 ad valorem tax year proceedings.[685] That study would have supported the Municipalities' position in that litigation that TAPS could operate down to 150,000 bbl/d or less, and may well have resulted in the Court finding a minimum capacity limit lower than the 200,000 bbl/d that this Court applied for that assessment year.[686]

413. In closing arguments to this Court, Owners' counsel asserted that the 2005 JTG Study was consistent with a 200,000 bbl/d limit south of Fairbanks because the study has a range of 200,000 to 135,000 bbl/d as the minimum limit, apparently referring to a North Pole off-take alternative scenario in the study.[687] This position is not supported by the evidence; the JTG Study unambiguously states that "the low-flow limit of the existing 48" TAPS pipeline was determined to be a PS [Pump Station] 1 rate of 135 MB/Day [135,000 bbl/d]."[688] And whatever the Owners' position as to how the 2005 JTG Study should be interpreted, the Owners' failure to bring that study forward resulted in the other parties, SARB, and this Court not being able to consider it until its production in the proceedings for the 2007 to 2009 tax years.

414. In 2010, BP Pipelines retained Phil Carpenter, a subject matter expert who was also used extensively by Alyeska in its Low Flow study, to determine whether TAPS could operate at levels below the 135,000 bbl/d threshold put forth in the 2005 JTG Study. At trial, Mr. Haines of BP Pipelines explained:

---

[685] Tr. 13580-81 (Mahoney).

[686] Amended Decision ¶ 122.

[687] Tr. 13580-81 (Mahoney).

[688] MUN7-3000 at 6, 7.

> The JTG study . . . essentially had two different paths that you could live with . . . One path was you would throw investments at TAPS and eventually the south leg would die at a rate of 135. You would start a railroading apparatus at that point. . . . the south leg always died first because of the extraction of oil at Fairbanks at the Fairbanks refinery . . . Except if you wanted to throw another $3 billion at the problem and replace the north leg with a replacement 20-inch line . . . [so as to be able to transport down to 45,000 bbl/day] . . . And the economic hurdle of paying for that $3 billion of replacement line investment created a very large stair-step in the economic profile, the granularity I was talking about.[689]

415. In a May 19, 2010 email, Mr. Haines provided Mr. Carpenter with a copy of the 2005 JTG Study and explained:

> You probably want to start with the executive summary. As we discussed on the phone, our reserves reporting relied on a 'low oil price' scenario and a 'high oil price scenario." These are identified in the report as Scenario 2 and Scenario 3. What we are looking for in your work effort is some sort of intermediate solution that could be used to extend the limit beyond 135 MBD [135,000 bbl/d] (Scenario 2), but would not have a $3 billion hurdle that would allow us to get down to 45 MBD [45,000 bbl/d]. In other words, something for a "middle oil price" scenario.[690]

Thus, the 2010 Carpenter Study was undertaken by BP Pipelines to obtain a minimum throughput level below 135,000 bbl/d that did not have a "$3 billion hurdle" associated with it that could be used for purposes of BP booking its proven reserves.[691]

416. A June 11, 2010 email from Mr. Carpenter contained a list of over a dozen low throughput options he had analyzed.[692] On June 15, 2010, Mr. Haines responded back that:

> I've had a chance to talk to our upstream reserves guys, and they advise that Option 2 (run cold and sweep with freeze suppressant) sounds like it might be pushing things too far, because it requires

[689] Tr. 11410-11 (Haines).

[690] MUN7-3046 at 1.

[691] Tr. 11411 (Haines); MUN7-3046 at 1.

[692] MUN7-3046 at 30.

> achieving a level of confidence in the physics of the problem – a level of "proof" that our study will not be capable of fully defining. So, they agree we can drop it from the list . . . .[693]

Mr. Haines then discussed the various other options, concluding:

> From a pragmatic viewpoint, it seems to me that item 1 (heaters) may be exactly what we're looking for (in terms of finding a sure-fire way to bridge between the 135 MBD [135,000 bbl/d] endpoint and the large capital cost of replacing the north leg). I say this because if we can find a way to lower the endpoint from 135 MBD [135,000 bbl/d] to say something in the range of 100 MBD [100,000 bbl/d] or less, that kind of solution would probably act to close the gap our reserves guys are seeking.[694]

417. On June 28, 2010 Mr. Carpenter provided Mr. Haines with a "status update on the low flow work" in which he opined:

> . . . I am beginning to think that it looks surprisingly good for ultra low flow below 100,000 [bbl/d]. . . Heating needs actually go down with decreasing flow after a certain point. In addition to heaters, the primary upgrades required are oil separation facilities in Valdez (which could rely to great extent on the existing tank system) plus a water treatment plant. Other upgrades would be safety upgrades required to deal with an extended pipeline shutdown. This option is particularly interesting because it also offers the possibility of shipping heavy viscous crude oil that may be coming down the line in the future. It does not currently appear that there are any downstream side effects.[695]

418. Consistent with that opinion, on July 20, 2010, Mr. Carpenter circulated a draft of the 2010 Carpenter Study: "The analysis concluded that point source heating of the oil is the best solution for operation of 100,000 [bbl/d]."[696] Mr. Haines' response to the draft stated:

---

[693] MUN7-3046 at 29.

[694] MUN7-3046 at 29. *See also* Tr. 11449-50 (Haines).

[695] MUN7-3052 at 1.

[696] MUN7-3056 at 6 (BP Pipeline interlineations omitted).

> Thanks for the updated report. This is shaping up nicely, and is exactly the "fit for purpose" product we were looking for. . . . Probably the most significant edits we've made to your most recent draft involved turning on the railroad when the PS-1 rate hits 140 MBD [140,000 bbl/d] (and turning off the south leg), and running the north leg down to 70 MBD [70,000 bbl/d]. This means some of the south leg heaters will likely not be installed at rates below 140 MBD [140,000 bbl/d] (because of laminar flow issues).[697]

419. The final version of the 2010 Carpenter Study was dated August 16, 2010 and concluded that TAPS could effectively operate down to throughputs between 100,000 bbl/d and approximately 70,000 bbl/d.[698] To operate at those throughputs, the study concluded that "[p]oint source heating of the oil (via heaters located at various intervals along the pipeline) is currently the best solution for enabling operations down to low throughput."[699]

420. The 2010 Carpenter Study did not foreclose lower throughput levels below its conclusions, acknowledging that other technologies apart from point source heating "may eventually offer better solutions with fewer unknowns, lower throughput limits and lower shutdown risk, but these options are less developed and well understood at this time."[700] The Study stated that "50,000 [bbl/d] to 70,000 [bbl/d] is probably the limit for [the point source heating] approach due to wax deposition and pigging concerns. Further reduction in flow will require investigation of other options that maintain higher flow velocities, such as seawater commodity supplementation."[701]

421. On August 23, 2010, Larkspur issued the companion report to the Carpenter Study. The Larkspur Study details the location, estimated cost, and timing (based upon flow

[697] MUN7-3051 at 1.

[698] Tr. 10404-07 (Haines); MUN7-3020 at 6-8.

[699] MUN7-3020 at 6. *See also id.* at 8 (laminar flow at "about 50,000 BPD").

[700] MUN7-3020 at 7.

[701] MUN7-3020 at 8.

rates) of the heaters necessary to operate all of TAPS down to 100,000 bbl/d.[702] Together with the Carpenter Study, the Larkspur Study demonstrates that the TAPS Owners are already considering the expenditure of significant resources to transport daily throughputs on TAPS far below the 300,000 to 350,000 bbl/d minimum throughput limit that the Owners are advancing in this case.

422. In the fall of 2010, BPPA used the lower minimum throughput determinations from the Carpenter Study in its transportation tariff calculations. Those calculations, in turn, were provided to BP Production forecasting personnel who then used that information to book BP's proven reserves in 2010.[703] That BP relied upon the Carpenter Study's 100,000 to 70,000 bbl/d low flow estimate to book its reserves is compelling evidence that these figures may be reasonably relied upon by this Court to determine the assessed value of TAPS.

423. At trial, the Owners maintained that TAPS' minimum throughput limit is much higher. They referred to the extensive work done on the 2011 Alyeska Low Flow Impact Study ("LoFIS"), as testified to by Alyeska employee Pat McDevitt, in support of their position that TAPS has an operational lower capacity limit of 300,000 to 350,000 bbl/d.[704] Mr. Carpenter, who prepared the BP Pipelines 2010 study for reserves purposes, was also a

---

[702] MUN7-3044; MUN7-3045. Thus, although BP Pipelines edited the final version of the 2010 Carpenter Study to reflect BP Pipelines' preference to "turn on" the North Pole Refinery, and thus assumes a limit of 140,000 bbl/d on the South leg, Larkspur's work is consistent with Mr. Carpenter's original analysis that did not distinguish between the low flow limits on the North and South legs.

[703] Tr. 11415-17 (Haines).

[704] Tr. 10751 (McDevitt).

core member of the Alyeska LoFIS team, with subject matter expertise in water transport, hydraulic size formation, and heat transfer.[705]

424. The LoFIS was an $11 million study by Alyeska that reviewed many potential low-flow issues – including water dropout and corrosion, ice formation within the crude, wax deposition, and potential pipe displacement due to ice lenses in the soil. The public version of the Low Flow Study expressly concluded that "[f]low volumes of less than about 350,000 BPD subject TAPS operations and pipeline integrity to greater degrees of uncertainty that require investigation and study beyond that accomplished through the LoFIS. *Measures to mitigate these issues utilizing the existing 48-inch pipe at throughputs below 350,000 BPD have not been determined at the date of this report.*"[706] Similarly, Mr. Haines testified that Mr. Carpenter and Larkspur "concluded that [TAPS] could run down to lower levels than what I understood the Alyeska team was currently examining," and that 300,000 bbl/d was the "lower range of [the LoFIS] effort."[707] This was also consistent with Mr. McDevitt's testimony that the purpose of LoFIS was "to look at TAPS' low flow down to 300,000 bbl/d".[708] This Court finds, based on the evidence presented at trial, that the LoFIS was primarily limited to studying operating challenges with throughputs down to 300,000 bbl/d and not below that level.[709] Its focus was not to determine TAPS' minimum throughput capacity.

---

[705] Tr. 10960-61 (McDevitt): MUN7-3020 at 12-14.

[706] Executive Summary of Low Flow Impact Study Final Report at 3 (public version, June 15, 2011), *available at* http://www.alyeska-pipe.com/Inthenews/LowFlow/LoFIS_Summary_Report_P6%2027_ExSum.pdf) (emphasis added). *See* Evidence Rule 201.

[707] Tr. 11403-04 (Haines).

[708] Tr. 10979 (McDevitt). *See also* MUN7-3056 at 6-7 (confidential statement by Mr. Carpenter).

[709] Tr. 10975-82 (McDevitt); Tr. 11404 (Haines).

425. While the LoFIS discussed many potential problems at lower throughputs and recommended further study for solutions, it did not establish by a preponderance of the evidence that TAPS cannot operate below 300,000 bbl/d. Although Pat McDevitt, the project manager for LoFIS, testified that it is "not possible" for TAPS to operate below 300,000 bbl/d, this Court found that testimony, when considered with all of the other evidence at trial presented on this topic, to be completely unpersuasive.[710] Mr. McDevitt declined to present himself as a subject matter expert in any of his areas of concern.[711] Furthermore, no other expert made an absolute statement as to TAPS' minimum capacity. For example, Alyeska engineer Joe Riordan testified that he did not know for a fact that TAPS could not operate at 100,000 bbl/d.[712] This Court concurs with the Department's assertion that in the case of Mr. McDevitt, "it is difficult to separate advocacy from engineering analysis that has been fully vetted and tested."[713]

426. Mr. McDevitt did not clearly articulate a specific reason why TAPS would cease to operate at any particular capacity level, but instead articulated a number of operational concerns that have not yet been fully studied.[714] For example, when asked for the primary reason why TAPS would be unable to operate below 300,000 bbl/d, he indicated low velocity pigging could constrain TAPS' operation at low flows.

---

[710] Tr. 11025-27, 11093 (McDevitt).

[711] Tr. 10963-68 (McDevitt).

[712] Tr. 5129 (Riordan).

[713] Department's Proposed Findings of Fact and Conclusions of Law ¶ 202.

[714] Tr. 11027-28 (McDevitt).

427. Pigging becomes more critical as the oil slows and the temperature of the oil decreases, because wax precipitation and deposition increase.[715] This wax deposition is primarily addressed through increased pigging of the pipeline. The August 2010 Carpenter Study used a 7-day pigging schedule with approximately 20 pigs in the pipeline for its 70,000 bbl/d scenario.[716] Mr. Carpenter nonetheless recognized that "pipeline scraper and inspection pig viability at low flow is a considerable concern at very low flow,"[717] and recommended that "Alyeska and/or its Owners implement a long-term research and development program to implement mission critical pigs."[718] But over one year after that report was issued, Mr. McDevitt testified at trial that he was unaware of any conceptual engineering work underway at Alyeska to address these pigging issues, and was unaware of any pig manufacturer that had been contacted for the purpose of designing, developing or testing low velocity pigs for TAPS.[719]

428. As noted above, BP pipelines provided extensive comments on a July 20, 2010 draft of Mr. Carpenter's Study. One exchange related to Alyeska's low flow work. BP Pipelines commented that:

> Recognizing that your work here goes beyond (and has a somewhat different focus than) the [Alyeska] Low Flow team's work, we want to ensure that everything said in this report would not contradict the work done by the Low Flow team or be in conflict with what their report might say when it is issued in 3Q. In particular, we've been picking up some recent rumors that the Low Flow team's optimism about achieving very low throughput rates has started to wane a little in

---

[715] Tr. 10918 (McDevitt).

[716] MUN7-3020 at 40.

[717] MUN7-3020 at 40.

[718] MUN7-3020 at 40.

[719] Tr. 11075-77, 11085 (McDevitt). *See also* Tr. 9224 (Malvick).

> recent months, but we don't know if there's any merit to this. So, we were hoping you could bring us up to speed on Friday.[720]

Mr. Carpenter responded: "I think that your concern is valid. The primary concerns are (1) the ability to pig the line at very low flow and (2) the impact of shutdowns and slowdowns on oil temperature and wax accumulation."[721] Another drafting note by BP Pipelines stated:

> Phil, I'm wondering whether you could develop a list of the additional heaters required to get down to say 70-80,000 [bbl/d]. This way we could get a sense of how impractical the number of heaters is getting to be as the rate goes below 100 MBD [100,000 bbl/d]. If it looks like maybe 3 or 4 more heating stations will do the job, then perhaps it is still within the range of being economic. I know this says nothing about the ability to pig at such low rates, or whether wax sedimentation is insurmountable. I guess what I'm trying to say is – is there any room to move this number lower without pushing the boundaries of good engineering judgment? Or, is 100 [100,000 bbl/d] about the limit of how low you think TAPS can go with point heating.[722]

Mr. Carpenter's response was:

> My biggest concern with ultra flow and heating is the ability to pig and the potential for wax sedimentation/sludge accumulation in laminar flow. I've refined my numbers a bit and right now the laminar flow limit in the north end is about 70,000 [bbl/d], which probably eliminates that sludge issue but does not solve the pig issue.[723]

429. Thus, while Mr. Carpenter expressed concerns with pigging, he was sufficiently confident the "pig issue" could be solved that he concluded TAPS could operate at the "70,000 [bbl/d] benchmark" discussed in his report.[724]

430. This Court finds the JTG and Carpenter studies, which were conducted by TAPS' largest Owner for the specific purpose of evaluating the ability of TAPS to operate at

---

[720] MUN7-3056 at 6-7.

[721] MUN7-3056 at 7.

[722] MUN7-3056 at 8.

[723] MUN7-3056 at 8.

[724] MUN7-3020 at 10.

throughputs well below 300,000 bbl/d and relied upon by BP for booking its proven reserves, to be far more persuasive than the LoFIS study in determining TAPS' minimum throughput capacity.

431. At trial, the Municipalities' expert Dr. Jerry Modisette persuasively opined why he had determined that TAPS could operate at 100,000 bbl/d. Indeed, Dr. Modisette asserted TAPS could operate at far lower throughputs than that, particularly if the oil were recirculated through the pumps so as to raise its temperature – a project Alyeska is planning to try this winter.[725]

432. With regard to the low-flow operational issues identified in the Alyeska study, including water dropout and corrosion, ice formation within the crude oil, ice lenses or frost heaves in the soil, and wax precipitation and deposition, the weight of the evidence at trial persuaded this Court that it is more likely than not that there will be engineering solutions to mitigate these problems on TAPS at throughputs down to 100,000 bbl/d or less.[726]

433. Heating the pipeline will likely be a major component of any low-flow mitigation approach. Mr. Malvick stated that Alyeska is currently studying and planning for heating TAPS via installation of point source heaters, enhanced recycling of crude at pump stations, bringing Pump Station 7 back into service as a heating station, enhanced pipeline insulation, and waste heat recovery at Pump Stations 3 and 4.[727] As of the time of trial in late 2011, Alyeska and the Owners had not yet purchased any heaters for TAPS.[728]

---

[725] Tr. 9014-15 (Modisette).

[726] *See, e.g.*, Tr. 8961-62 (Hisey).

[727] Tr. 1969, 1974, 1978-80 (Malvick).

[728] Tr. 1828-29 (Riordan).

434. The August 2010 Larkspur Study estimates approximately $2 billion in undiscounted costs for heating TAPS so as to be able to transport 100,000 bbl/d.[729] This is based on the 2010 Carpenter Study's use of substantial redundancy resulting in 70% excess heating capacity.[730] Thus, the actual cost could well be considerably lower. However, even Larkspur's estimated expense is self-evidently economic in light of the value of TAPS' proven reserves. The Court was persuaded by Mr. Hisey's testimony that even if the heating and other mitigation measures cost upwards of hundreds of millions of dollars in the coming decades, it would still be economical to make such investments to keep TAPS operating at and below 100,000 bbl/d "to move North Slope crude oil and keep that transportation base available for future fields, future production."[731]

435. As noted above, Mr. Haines used the 2010 Carpenter Study and the Larkspur Study as the basis for TAPS' minimum throughput capacity in developing the per barrel transportation tariffs that BP relied upon to book its proven reserves.[732] At the trial de novo, Owners' counsel asked Mr. Haines what weight he would give the 2010 Carpenter Study today if he were to determine TAPS' minimum throughput capacity, after Alyeska's $11 million low flow study had been completed.[733] Mr. Haines testified:

> It seems to me that if I had to sit back and do tariffs again, I would be – have to give a lot of weight to – to the one that seems to me to be – have more depth behind it and engineering facts, and that would have to be – I would have to seriously weight what I saw with – with the Alyeska result.[734]

[729] MUN7-3045 at 2.

[730] MUN7-3020 at 29-31.

[731] Tr. 9000 (Hisey).

[732] Tr. 11474-75 (Haines).

[733] Tr. 11484 (Haines).

[734] Tr. 11485-86 (Haines).

Thus, Mr. Haines did not say that he believed the 2010 Carpenter Study was inaccurate, presented incorrect information, or was improper to rely upon to book reserves in the past or future, but only that he would "seriously weigh" the Alyeska opinions presented at trial by Mr. McDevitt.

436. The Owners did not seek to have Mr. Carpenter testify at trial, notwithstanding the Court's specific indication during trial that a motion could be brought to do so.[735]

437. This Court finds the conclusions reached in the 2005 JTG study, together with the opinions reached in the 2010 Carpenter Study and Larkspur Study, as well as the opinions of Dr. Modisette and Mr. Hisey, to be more credible and persuasive than Mr. McDevitt's opinion on TAPS' minimum throughput capacity.

438. For the foregoing reasons, and after careful consideration of all of the evidence presented at trial, this Court finds it more likely than not that TAPS can effectively transport throughputs at least down to a minimum flow rate of 100,000 bbl/d.

b. Proven Reserves

i. The Definition of Proven Reserves

439. The applicable statute requires consideration of the "estimated life of the proven reserves of gas and unrefined oil then technically, economically and legal deliverable into the transportation facility."[736]

440. Various definitions of the term "proven reserves" have been advanced by the parties and considered by this Court during the course of these proceedings.[737] For the

[735] Tr. 11505 (Court); Alaska Civil Pattern Jury Instruction 02.23.

[736] AS 43.56.060(e)(2).

2006 tax year, this Court declined to further define proven reserves beyond the statutory language, and held that the statute required an estimation of the total proven reserves, and then a determination made as to which of those proven reserves were deliverable to the pipeline as of the valuation date.[738]

441. In an order issued on August 16, 2011, this Court again declined to create a more refined definition of "proven reserves" than is set forth in the statute, and again held that the statutory phrase "then technically, economically and legally deliverable" provides a further restriction on the amount of proven reserves that can be considered in determining the full and true value of TAPS.[739]

442. In their proposed findings, the Owners urge this Court to adopt a requirement that reserves be proven to a level of "reasonable certainty" before they can be considered as "proven reserves" for ad valorem tax purposes. They cite to the Securities and Exchange Commission ("SEC") definition, which effective January 1, 2010, provides as follows:

> Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.[740]

---

[737] *See* Owners' Mot. for Rule of Law on Meaning of Proven Reserves within AS 43.56 (May 27, 2011); Municipalities' Opp'n to TAPS Owners' Mot. for Rule of Law on Meaning of Proven Reserves within AS 43.56 (June 29, 2011); 2007 R. 3541- 3561; Tr. 9705-06 (Van Dyke).

[738] *See* Order re TAPS Owners' Motions of May 27, 2011 at 2, n. 3 (Aug. 16, 2011).

[739] *See* Order re TAPS Owners' Motions of May 27, 2011 at 2 (Aug. 16, 2011).

[740] 17 CFR § 210.4-10 (effective 2010); Owners' Proposed Findings of Fact and Conclusions of Law ¶ 698.

443. The Owners note that publicly traded companies listed on the U.S. stock exchange must report their proven reserves using this SEC definition.[741] They assert that "[t]he SEC rules provide for a consistent and reliable industry understanding of the term and the meaning of 'proven reserves' for booking those reserves for financial reporting and for public disclosures."[742] They argue that this standard should be adopted by this Court for the ad valorem assessment of TAPS, as it reflects "current technical understanding of the term as used in the United States."[743]

444. In effect, the Owners' urge the adoption of a heightened burden of proof so as to require that the reserves be proven to a level of "reasonable certainty" before they can be considered in the ad valorem assessment of TAPS.

445. A 1965 Society of Petroleum Engineers' ("SPE") definition of "proved reserves" in effect when AS 43.56 was enacted read as follows:

> Proved Reserves–The quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions. They represent strictly technical judgments, and are not knowingly influenced by attitudes of conservatism or optimism.[744]

446. There is a similarity between AS 43.56.060(e)(2) and the 1965 SPE definition for "proved reserves," and it is possible that Legislators considered the SPE definition when drafting the ad valorem tax statutes.[745] And yet, as this Court has previously noted, the Legislature did not articulate any particular confidence level in the statutory definition of

[741] Tr. 9867-68 (Hoolahan).

[742] Owners' Proposed Findings of Fact and Conclusions of Law ¶ 697.

[743] Owners' Proposed Findings of Fact and Conclusions of Law ¶ 702.

[744] 2007 R. 3546.

[745] *See* 2007 R. 3534.

"proven reserves" for ad valorem tax purposes, such as proven by a "preponderance of the evidence" or "reasonable certainty."[746]

447. "Preponderance of the evidence is the general burden of persuasion in civil cases."[747] On occasion, such as with civil statutes that are quasi criminal in nature, the Alaska Supreme Court has established a higher burden. But in this tax case, and in the absence of a clear legislative articulation of a heightened standard, the preponderance of the evidence standard should control.

448. Moreover, no persuasive justification has been demonstrated here for creating a heightened burden of proof for ad valorem tax purposes. Government reporting agencies such as the SEC require a heightened burden of proof from oil producers that the reserves they are asserting as proven have actually been ascertained to a degree of reasonable certainty. That heightened burden, however, is imposed upon the entities that have full access to the data they are required to submit, and is intended for investors to be able to rely upon in formulating investment decisions.

449. The history of this case demonstrates that it has been exceedingly difficult for the Municipalities to obtain any proven reserves information from the Owners and their affiliates. Only a limited amount of reserves information has been made available to the Municipalities – and certainly not due to a lack of effort on their part both before the trial court and on repeated petitions for review to the Alaska Supreme Court. To require a

[746] *See* Amended Decision ¶ 396.

[747] *Fernandes v. Portwine,* 56 P.3d 1, 6 (Alaska 2002) (citing *Addington v. Texas*, 441 U.S. 418, 423 (1979) (the burden in typical civil cases is preponderance of the evidence); *Spenard Action Comm.*, 902 P.2d at 775 (the general civil standard is preponderance of the evidence); *Cavanah v. Martin,* 590 P.2d 41, 42 (Alaska 1979) ("The standard of proof in civil cases is proof by a preponderance of the evidence."). *See also* AS 43.05.435(1) (in tax appeals heard by administrative law judge, the judge shall "resolve a question of fact by a preponderance of the evidence, or if a different standard of proof has been set by law for a particular question, by that standard of proof.").

heightened burden of proof of the proven reserves from the Municipalities when they have been unable to obtain all of the proven reserves information they have so vigorously sought from the Owners and their affiliates could result in an ad valorem valuation that is not a "full and true value" of the pipeline. This Court finds it more likely that a construction of the statute "that rigidly adopted the petroleum industry's concept of proved reserves would lead to impermissible inequities in tax assessment."[748]

450. The Owners also cite to AS 01.10.040(a) in urging the adoption of the SEC definition. This statute provides that "[t]echnical words and phrases and those which have acquired a peculiar and appropriate meaning, whether by legislative definition or otherwise, shall be construed according to the peculiar and appropriate meaning."[749] But the record demonstrates that in addition to the reserves information that an oil producer provides to the SEC using the government's reporting standards, an oil producer also maintains its own proprietary reserves information, which can be based on a variety of different economic and other assumptions from the SEC requirements.[750] The record establishes that the term "proven reserves" has not acquired a peculiar or appropriate meaning. Accordingly, this Court finds that for ad valorem tax purposes under AS 43.56, reserves must be proven by a preponderance of the evidence, and not by any heightened standard.

451. The word "then" preceding "technically, economically and legally deliverable into the transportation facility" in AS 43.56.060(e)(2) imposes a temporal restriction that

---

[748] *Maples v. Kern County Assessment Appeals Bd.*, 103 Cal. App. 4th 172, 196 (Cal. Ct. App. 2002). *See also* Municipalities' Proposed Findings of Fact and Conclusions of Law ¶¶ 677, 678.

[749] Owners' Proposed Findings of Fact and Conclusions of Law ¶ 691.

[750] Tr. 9718-24 (Van Dyke).

requires that for proven reserves to be included in the valuation analysis of TAPS, they must be technically, economically, and legally deliverable as of the valuation dates each year.

452. This Court interprets the requirement that the oil be "technically" deliverable into the pipeline to mean that the technology exists as of the lien date for the oil to be deliverable to the pipeline. This Court again finds that the existence of pipeline and production facilities to a particular field as of the lien date is not a prerequisite for those reserves to be considered technically deliverable under the statute, so long as the technology exists for the oil to be deliverable to the pipeline as of the lien date.[751] This finding is consistent with many definitions of the term "proven reserves," including those adopted by the SEC and the SPE, which distinguish between proved developed reserves and proved undeveloped reserves.[752] Reserves that do not have infrastructure in place are still considered proven, but are categorized as proved undeveloped.[753]

453. Further, as previously discussed in this decision, this Court adopts the Board's interpretation of the statutory provision that reserves be "technically deliverable ... into the transportation facility" to permit a pipeline owner to prove by a preponderance of the evidence that a pipeline has a minimum throughput capacity.

454. This Court finds that the "legally deliverable" requirement is satisfied so long as the totality of the circumstances demonstrate that it is reasonable to assume that all necessary permits and licenses to allow for the extraction of proven reserves from a given

---

[751] *See* Amended Decision ¶ 401.

[752] Tr. 9872 (Hoolahan).

[753] Tr. 10084 (Hoolahan).

pool will be granted or renewed, and there exist no legal prohibitions against delivering those reserves to TAPS as of the lien date.

455. In the case of the Point Thomson Unit ("PTU"), the Department of Natural Resources had terminated the unit as of November 2006, so reserves from the PTU should not be included in the proven reserves as of the January 1, 2007 lien date because of the legal prohibition on development. In December 2007, the Superior Court reversed the unit termination decision and remanded the matter back to the agency for further proceedings. Thus, the PTU should be included as legally deliverable proven reserves as of the January 1, 2008 lien date.[754] But as of the January 1, 2009 lien date, the unit had again been terminated by the agency, and the appeal to the superior court was pending. Thus, the PTU should not be included in the proven reserves analysis as of that date. The PTU satellites have been included as proven reserves in all three of the lien years since no persuasive evidence was presented that they were included within the agency's unit termination decisions.

456. This Court was completely unpersuaded by the testimony of the Owners' witness Jack Hartz that the "legally deliverable" provision set forth in the statute includes only those quantities of oil that are contained in reservoirs for which the producers, as of the lien date, have every permit and license necessary to allow immediate extraction and delivery of crude oil to TAPS.[755] Such an approach would result in an improper valuation of the pipeline.

---

[754] *See ExxonMobil v. State*, Superior Ct. Case No. 3AN-06-13751 CI.

[755] Tr. 10143-45 (Hartz).

457. Natural gas liquids ("NGLs") produced at Prudhoe Bay that are contractually committed for shipment to Kuparuk would not be legally deliverable to TAPS.[756] However, the Owners failed to present sufficient evidence as to the amount of such reserves.[757]

458. To be economically deliverable, the anticipated price for a barrel of oil to be delivered to market must exceed the cost of its production, including the cost of transportation. Each party performed an economic analysis of the proven reserves for this proceeding.

459. Thus, so long as oil in each of the three categories of ANS production established by the Department of Revenue – producing, under development, and under evaluation – was economically, technically, and legally deliverable into TAPS as of the lien date, as proven by a preponderance of the evidence, that oil should be included when estimating the economic life of TAPS for ad valorem tax purposes.

460. This is consistent with the testimony of experts in this case and before SARB that "technically, economically, and legally" are common elements of proved reserves definitions,[758] and that their determination of "proven reserves" would not have been materially different had the "technically, economically, and legally" language been absent.[759] That is because each of these three requirements are explicitly or implicitly contained in most, if not all, definitions of proved reserves.

---

[756] Tr. 10038 (Hoolahan).

[757] There are references to the exclusion of these NGLs in some of Mr. Hoolahan's charts, but the amounts are unspecified. *See, e.g.*, T0-07-0092 at 39, 46, 53.

[758] Tr. 10579-81 (Greeley); Tr. 10037-38 (Hoolahan); Tr. 10527-29 (Molli); Tr. 9831-32, 9837-39 (Van Dyke); Tr. 9412 (Platt); 2007 SARB Tr. 0765, 0772 (Garb).

[759] Tr. 9870-71 (Hoolahan); Tr. 9708-09 (Van Dyke).

461. The economically recoverable proven reserves estimates, in billions of barrels of oil, presented by each of the parties at trial were as follows:

Party	2007	2008	2009
Owners Hoolahan (Initial Report)[760]	1.884	1.949	1.307
Owners Hoolahan (Corrected)[761]	4.163	4.119	3.092
Department of Revenue Molli / Greeley[762]	5.436	5.169	4.929
Municipalities Platt / Van Dyke[763]	8.198	7.759	7.362

In addition to the foregoing, confidential proven reserves estimates from BP Exploration (Alaska) Inc. were provided through discovery and admitted as evidence. The Owners and the Department did not present any witness that directly addressed BPXA's confidential estimates.

\\

\\

\\

\\

\\

[760] T0-07-0146.147. These are Mr. Hoolahan's 1P estimates – which he defines as "proved developed reserves." T0-07-0007.08.

[761] T0-07-92 (corrected) at 22. These are Mr. Hoolahan's 2P estimates – which he defines as "proved plus probable developed reserves" with some augmented data from Mr. Molli. T0-07-0007.08. The 1P estimates do not appear in his corrected report.

[762] SOA7-6 at 11. Note, however, this assumes a 150,000 million bbl/d throughput limitation. Actual proved reserves would be higher.

[763] MUN7-4306 at 6; MUN7-4313 at 6; MUN7-4309 at 7.

462. **[CONFIDENTIAL – SEE SEALED ENVELOPE.]** [redacted]

463. The parties also presented some evidence of reserves information that has been made publicly available through various government agencies. This included a Department of Energy Report dated August 2007 which estimated that the remaining

---

[redacted]

economically recoverable oil from existing fields on the ANS was between 6 and 7 billion barrels as of December 31, 2004.[770]

464. The Owners' appraiser Michael Remsha did not rely upon the Owner's reserves expert Shaun Hoolahan's proven reserves estimates, but instead used the Department of Revenue's throughput projections to which he applied a discount. His discounted remaining throughput projections as of the lien dates ranged from 2.0 billion barrels to 6.2 billion barrels.[771]

ii. The Municipalities' Production Forecasts and Reserves Estimates Generally Provide a Reliable Basis for Determining TAPS' Estimated Proven Reserves

465. Dudley Platt is one of the preeminent production forecasters in the state, although he is not a petroleum engineer. He began making oil production forecasts for the State of Alaska in 1989.[772] Mr. Platt prepared a production forecast for the Department every year through 2009.[773] This Court relied on Mr. Platt's production forecast to determine TAPS' end-of-life in the 2006 tax year trial.[774]

466. Mr. Platt used a comprehensive "lease sale to abandonment" approach to his forecasting in which he considered lease acquisition, unitization and field development, and how multiple pools produce using evolving technologies and numerous reservoir drive mechanisms to common surface facilities.[775]

---

[770] MUN7-0001-4232.

[771] TO-07-0004.0260.

[772] Tr. 9338 (Platt).

[773] MUN7-0238 at 21.

[774] Amended Decision ¶ 398.

[775] Tr. 9343-48 (Platt).

467. Mr. Platt also testified that he relies upon reports filed by the producers with the Alaska Oil & Gas Conservation Commission in determining what proved reserves are technically recoverable.[776] Those reports detail not only industry estimates regarding the quantities of oil in place, but also industry estimates regarding the amounts of oil recoverable using established methods of extraction.[777] These estimates are based on standard industry techniques, including seismic mapping, computer simulation, and exploratory drilling.[778] The evidence at trial demonstrated that the estimates of the economic life of Prudhoe Bay reported by the BP Prudhoe Bay Royalty Trust ("Royalty Trust") to the SEC correlate well with Mr. Platt's economic models when he used the SEC fixed price for comparison purposes.[779]

468. Decline curve analysis is one component in the determination of the economic life of ANS proven reserves.[780] Mr. Platt's forecast incorporated a decline curve analysis at the pool level, as opposed to a well-by-well analysis used by both the Owners' and Department's witnesses.[781] Mr. Platt persuasively testified that, based on his experience working in the oil industry, long-range production forecasters do not use decline curves on a well-by-well basis.[782] Mr. Van Dyke explained that well-by-well analysis can work well for a small lease in Kansas with four wells, but not for a field with 1,000 wells that are regularly being turned on and off: "it's not the best approach to use a well-by-well method as

[776] Tr. 9351-52 (Platt).

[777] Tr. 9351-52 (Platt).

[778] Tr. 9351-53 (Platt); Tr. 9384-85 (Platt).

[779] Tr. 9388-89 (Platt).

[780] Tr. 10498-99 (Molli).

[781] Tr. 9356 (Platt).

[782] Tr. 9431-32 (Platt).

compared to the pool – a pool level method to forecast production."[783] Decline curve analysis at the well level requires subjective analysis of highly variable historic data to estimate future production rates for each well.[784]

469. **[CONFIDENTIAL – SEE SEALED ENVELOPE.]** [redacted]

470. The legislative history of AS 43.56 supports the use of a pool forecasting methodology. At a 1973 Finance Committee hearing on the bill, "Mr. Heier asked if the Division of Oil & Gas could furnish the state assessor's office projections well by well as to future productions. Mr. Burrell [of the Division] said it could be done more accurately on a field basis, as one well could dry up immediately."[786]

471. Based on the evidence presented at trial, this Court finds that for determining the economic life of TAPS, a pool-based analysis is generally preferable to a well-based analysis.

472. One of the components of a decline curve analysis is the "b-factor." Mr. Platt, on a pool basis, and Mr. Molli, on a well-by-well basis, both used b-factors to depict the rate at which oil production declines over the life of the projection. Mr. Platt was criticized for his use of b-factors greater than the value of 1.0 for several pools because some theorists maintain that b-factors must fall between the value of zero and one, and may never be greater than the value of one.

---

[783] Tr. 9764 (Van Dyke).

[784] Tr. 9425-28 (Platt); Tr. 9429-32 (Platt); Tr. 9356 (Platt).

[redacted]

[786] *Minutes* at 50, H. Finance Comm., 8th Leg., 1st Spec. Sess. (Oct. 22, 1973) [2007 R. 9736].

473. A b-factor greater than 1.0 projects infinite production over an infinite period of time.[787] Yet Mr. Molli acknowledged at trial that when a b-factor of .5 is used it takes approximately two billion years for production to converge to close to zero.[788] Thus, whether a b-factor assumption models a pool or well that produces for two billion years or forever is not significant, because forecasters use economic tests to terminate production at some point several decades in the future – long before two billion years.[789]

474. **[CONFIDENTIAL – SEE SEALED ENVELOPE.]** [redacted]

475. Mr. Platt used b-factors for Prudhoe Bay of 1.0 for 2009, and 1.054 for both 2008 and 2007.[792]

476. Witnesses for both the Department and the Owners asserted that Mr. Platt had overestimated short-term production. But Mr. Platt persuasively testified that the major reason for that over-estimation was due to short-term interruptions in production and the

---

787 Tr. 10503-04 (Molli).

788 Tr. 10546 (Molli).

789 Tr. 10546-47, 10559-61 (Molli).

[redacted]

792 SOA7-12 at 5.

delay of ANS fields and projects coming online, such that the oil he forecasted will eventually be recovered.[793]

477. Mr. Platt's economic testing assumed that a pool will stop producing oil during the first year that the costs for extracting the oil from that pool exceed the revenue generated from the sale of that oil.[794] He also assumed that operating costs would remain flat over the life of a given field. In reality, real operating costs typically decrease over the economic life of the field.[795]

478. Economic testing of reserves also requires forecasting the future price of oil. There are several methods: (1) "point in time" forecasting, which uses the price of oil on a specific date as the price for all future oil sales;[796] (2) basing the price on historical data over an established time period;[797] and (3) setting prices based upon a forward-looking forecast.[798]

479. Until 2010, the SEC required producers to use "point-in-time" forecasting using the price of oil on the last trading day of the relevant calendar year as the price for all future sales.[799] For investors, such an approach permits a meaningful comparison among different companies. But this Court finds that the historical "point in time" method of price forecasting for ad valorem tax purposes results in substantial year-to-year volatility of economic end-of-

---

[793] Tr. 9447-48 (Platt); Tr. 9989-90 (Hoolahan).

[794] Tr. 9371-72 (Platt).

[795] Tr. 9374-75 (Platt); Tr. 9407-09 (Platt) (confidential); Tr. 9561-62 (Platt) (confidential); MUN7-4406 at 3, 5; Tr. 10066-67 (Hoolahan).

[796] Tr. 10029 (Hoolahan).

[797] Tr. 10620-21 (Greeley).

[798] Tr. 9376-79 (Platt); Tr. 9558-60 (Platt).

[799] Tr. 9420-21 (Platt).

life estimates. The SEC ameliorated the volatility of this approach to some degree when it amended its regulations in 2010 to use the monthly average price of oil during the prior year instead of December 31.[800] The Court finds it more reasonable for the purposes of economic testing under AS 43.56.060(e)(2) to use a historical average of prices or credible forward-looking oil price forecasts.

480. Mr. Platt relied upon the U.S. Department of Energy's Energy Information Administration ("EIA") price forecast, which forecasted real market price growth for each of the three assessment years at approximately 1% per annum.[801] Based on the evidence presented at trial, this Court finds that reliance on that forecast was reasonable. Oil prices during the three assessment years were volatile, such that the forward-looking projections made by the EIA during that period varied considerably. Yet the highest oil price forecasted by the EIA for calendar year 2011 during the assessment years was $74.08 per barrel, while the actual price of oil on October 18, 2011 was $113 per barrel.[802] Mr. Platt also explained that due to the highly progressive nature of Alaska's production tax, oilfield economics at high real oil prices are not materially affected by price variations.[803] Overall, this Court found Mr. Platt's production forecast and economic testing to be persuasive.

iii. The Forecasts and Reserves Estimates Offered by the Owners' Witnesses were not Persuasive

481. The Owners presented economist Roger Marks to testify with respect to proven reserves. Mr. Marks' testimony regarding the reserves estimates he derived from

---

[800] Tr. 9386-87 (Platt); Tr. 9949-50 (Hoolahan).

[801] Tr. 9376-79 (Platt).

[802] Tr. 9565-67 (Platt). *See also* Tr. 10039-40 (Hoolahan).

[803] Tr. 9565-66 (Platt).

the oil producers' SEC filings was not persuasive.[804] His testimony was at odds with Mr. Van Dyke's testimony regarding the SEC filings by the BP Prudhoe Bay Royalty Trust. This Court found Mr. Van Dyke's testimony to be considerably more persuasive, in large part because Mr. Van Dyke correlated his findings with the BPXA confidential reserves information and also referred the Court specifically to the precise language and numbers in the SEC filings that informed his analysis.[805]

482. Petroleum engineer Shaun Hoolahan presented production forecasts and reserves estimates on behalf of the Owners. For a number of reasons, this Court found his conclusions to be unpersuasive.

483. Unlike all the other production forecasts presented in this case, Mr. Hoolahan's reports do not specify the expected amount of oil production each year for each of the fields over the projected life of that field. Instead, that information is set out in aggregated charts that are imprecise.

484. Mr. Hoolahan testified whether his estimated production had been higher or lower than the actual production for the past few years. But the testimony did not include the amount of production he had estimated, but simply indicated whether his prediction had been too high or too low.[806] Without knowing the amounts he had predicted to compare to actual production, the analysis was unpersuasive.

[804] Tr. 10391-93 (Marks).

[805] Tr. 9727-33 (Van Dyke). The testimony there refers to MUN7-4072 (excerpts of the BP Royalty Trust SEC filings), which was admitted as MUN7-0001 at tab 58, p. 2006. At closing arguments, Owners' counsel distributed and referred to various pages from what appeared to be SEC 10-k 2008 filings from ConocoPhillips.

[806] *See generally* T0-07-0007 at 103-119.

485. Mr. Hoolahan testified that he used only publicly available information to perform his initial analysis.[807] The reason for this is not clear, given that the record in this case demonstrates that at least one of the TAPS Owners, BPPA, has had access to ANS reserves information through its affiliate. Mr. Hoolahan acknowledged that he had insufficient information for a proper assessment of proved undeveloped reserves.[808] He later augmented his report with information he received from the Department's expert Mr. Molli to increase his proven undeveloped estimates.[809]

486. Mr. Hoolahan assumed five years of new wells from the date of each assessment. After that, he assumed that no new wells would be drilled on the ANS.[810] This restrictive assumption is not reasonable, based upon this Court's review of all the evidence.

487. Mr. Hoolahan used what he termed a "cut-cum" methodology on a well-by-well basis to assess ANS reserves, which is shorthand for water cut vs. cumulative oil.[811] Although this Court has been presented with considerable amounts of complicated technological information during this case, and has strived and in large part succeeded in understanding it, this Court found Mr. Hoolahan's lengthy explanation of the methodology that he used to determine ANS reserves to be virtually incomprehensible. Additional efforts by this Court to try to understand Mr. Hoolahan's methodology by reviewing his reports were also unsuccessful, particularly because no actual production estimates by year or other data was provided except in conclusory form and imprecise charts.

[807] Tr. 10074 (Hoolahan).

[808] Tr. 10072 (Hoolahan).

[809] Tr. 10074 (Hoolahan).

[810] Tr. 9930-31 (Hoolahan).

[811] Tr. 9877-78, 9961 (Hoolahan).

488. Mr. Hoolahan indicated that he allowed his forecast to be guided by Mr. Hartz's restrictive interpretation of the term "legally deliverable."[812] And he testified that he had analyzed only 12 of the 36 pools on the ANS because of time constraints.[813] These limitations further impacted the reliability of Mr. Hoolahan's estimates.

489. Mr. Hoolahan asserted that his results were comparable to Mr. Molli's results. However, Mr. Hoolahan was comparing his P2 case, which consisted of both proved and probable reserves, to Mr. Molli's proved reserves, and only after Mr. Hoolahan made a number of adjustments to Mr. Molli's calculations. This Court was not persuaded that Mr. Hoolahan's results were comparable to Mr. Molli's results.

490. Since ANS producers have access to field-specific information, internal industry information is very likely to assist forecasters in attaining the most reliable estimates regarding future ANS production and the volume of proven reserves that are likely to flow into TAPS during its economic life.[814] But the Owners have chosen not to offer into evidence or have their witnesses meaningfully review any internal reserves estimates and related documentation. This is despite the fact that a number of BP Pipelines and BP Exploration internal documents that were received through discovery were moved into evidence and discussed by the Municipalities' witnesses in their testimony at trial.

491. SARB observed the following in its Certificate of Determination for the 2007 assessment year:

> The Board also found that the Owners failed to take advantage of the opportunity to provide the Division with persuasive data to challenge

[812] Tr. 10070 (Hoolahan).

[813] Tr. 10070-71 (Hoolahan).

[814] Tr. 10450-51 (Molli).

> the reserves estimates or throughput projections used by the Division if the Owners have such data. The Board found that the Owners chose not to the [sic] share information that the Owners and their parent companies possess regarding throughput and proven reserves with the Division or the Board and instead chose to present evidence and testimony from outside experts who did not have access to the information the Owners possess that was not already in the public record, and who lacked adequate direct experience with, or expertise about, the TAPS or the Alaska North Slope reserves.[815]

492. The internal reserves and long term production forecasting information that was made available through discovery was not reviewed by two of the Owners' reserves witnesses, Mr. Hartz or Mr. Marks, and only cursorily reviewed by Mr. Hoolahan (and not synthesized into his analysis).[816] Further, Mr. Hoolahan did not have representatives of the Owners or their affiliated producers review his reserves estimates to provide feedback.[817] This is despite the fact that the internal reserves information presented at trial was substantially different from Mr. Hoolahan's conclusions. The fact that none of the Owners' reserves experts meaningfully addressed the BP internal reserves information at trial had a substantial negative impact on the weight this Court accorded to their testimony.

493. The failure of the Owners (and the Department) to address the confidential data provided in discovery is further demonstrated by the fact that neither party has submitted any proposed findings that require confidentiality.

494. The Owners maintain that any deficiency in this regard was remedied by the Department's access to and reliance upon highly confidential proven reserves information in

[815] MUN7-0234 at 15.

[816] Tr. 10162 (Hartz); Tr. 10403 (Marks); Tr. 10062 (Hoolahan).

[817] Tr. 10077 (Hoolahan).

the preparation of its forecasts.[818] This argument is unpersuasive. Having had the opportunity to compare the limited confidential data that the Department has received from the producers with the confidential reserves information that was received from BPXA in discovery, this Court is fully persuaded that the best available reserves information in this case is BPXA's confidential documentation with respect to those fields in which it has an interest, and not the documents produced to or maintained by the Department.[819]

495. The determination of the estimated proven reserves should be assessed in light of the evidence available to, and presented by, each of the parties.[820] The Owners did not persuasively rebut the Municipalities' evidence regarding proven reserves, including information contained in filings by the BP Royalty Trust and the confidential reserves information produced in discovery.

iv. The Department's Production Forecasts and Reserves Estimates Are Unreliable

496. Petroleum engineer Frank Molli performed a production forecast for the Department. The Assessor, Mr. Greeley, then made various adjustments to the forecast and also applied an economic test to it.

497. The Court finds that although Mr. Molli considered the three categories of proven reserves, his well-by-well analysis and methodology failed to capture significant barrels of oil that should be properly included in forecasts for each of the assessment

---

[818] Owners' Proposed Findings of Fact and Conclusions of Law ¶ 719.

[819] *See, e.g., Department's Proposed Findings of Fact and Conclusions of Law* ¶ 24 ("In the 2007 through 2009 assessments, the assessor sought information from the TAPS Owners and, as to reserves and production forecasting information related to their affiliate ANS producers, received very little.")

[820] Alaska Civil Pattern Jury Instruction 02.23

years.[821] Mr. Molli also did not save all of the data necessary to permit a complete review of his work product.[822] And Mr. Molli did not prepare a forecast for each assessment year,[823] but rather presented his forecast from the Fall 2010 Revenue Sources Book, which the Assessor then adjusted backwards for each of the three lien years.[824]

498. Consistent with his critique of Mr. Platt's use of b-factors over 1.0, Mr. Molli testified that he adjusted all of his b-factors to be no greater than 1.0.[825] But at trial Mr. Molli was unable to articulate why he had set his b-factors at 1.0 as opposed to within the range prescribed by the authorities he relied on: "So why did you arbitrarily adjust your b factors greater than 1 down to 1 rather than .7?", Mr. Molli responded "That's a good question. I just left them at 1."[826]

499. Mr. Molli did not attempt to incorporate BPXA's internal forecasts into his analysis or use them to validate the reasonableness of his results.[827] As with the Owners' experts, Mr. Molli's failure to do so had a substantial negative impact on the weight this Court accorded to his reserves analysis.

500. Mr. Greeley, without Mr. Molli's input, adjusted the data contained in Mr. Molli's forecast to retroactively produce proxy forecast figures for the three lien years.[828] Mr.

---

[821] Tr. 9757-59 (Van Dyke) (confidential).

[822] Tr. 10472-43 (Molli) (confidential); Tr. 10543-45 (Molli).

[823] Tr. 10532 (Molli).

[824] Tr. 10446 (Molli); Tr. 10589-97 (Greeley) (confidential).

[825] Tr. 10456 (Molli); Tr. 10548-50 (Molli); Tr. 9441-44 (Platt); MUN7-4360 at 2-5.

[826] Tr. 10550 (Molli).

[827] Tr. 10533-35 (Molli).

[828] Tr. 10446 (Molli); Tr. 10587-88 (Greeley).

Greeley does not have a background in reservoir engineering or production forecasting.[829] Mr. Greeley's reports did not explain the methodology he used to retroactively create the proxy forecasts for the assessment years, nor did he sufficiently explain that methodology at trial.[830]

501. Overall, this Court finds that Mr. Molli's Fall 2010 forecast, and the Assessor's adjustments to that forecast for each tax year, are considerably less reliable than the production forecast prepared by the Municipalities' witness Dudley Platt.

v. Conclusions on the Proven Reserves

502. BP Exploration (Alaska), an affiliated company of one of the taxpayers in this case, BP Pipelines, provides SEC reserves information on the Prudhoe Bay field each year to the BP Prudhoe Bay Royalty Trust.[831] The information is audited by an independent oil and gas consultant, Miller and Lents, before submission to the SEC.[832] The Trust's SEC filing for year-end 2005, using the SEC's heightened "reasonable certainty" standard for proven reserves, represented that "BP Alaska expects continued economic production [from Prudhoe Bay] at a declining rate until the year 2065 . . . ."[833] In the year-end 2006, 2007 and 2008 SEC 10-K filings, BP represented continued economic production at Prudhoe Bay until 2062, 2075 and 2049, respectively.[834] The 2049 economic end-of-life calculation for December 31, 2008 was based on the price of oil on that date of $44.60, while the

---

[829] Tr. 10660-61 (Greeley).

[830] Tr. 10592 (Greeley) (confidential).

[831] MUN7-0001 at 3000. *See also* 15 U.S.C. § 78ff(a) (up to $15 million and 20 years in prison for a natural person, up to $25 million for companies).

[832] MUN7-0001 at 3002.

[833] MUN7-0001 at 3031.

[834] MUN7-0001 at 3018, 3009, 2049.

December 31, 2006 economic end-of-life date was based on an oil price of $61.06.[835] Both of these amounts were considerably below the average price of oil during those years and its predicted future price.[836] The 2007 filing was based on the price of oil on December 31, 2007 of $96.01.

503. The following chart sets out the assumed end-of-life in the Prudhoe Bay Royalty Trust SEC filings and as calculated by each of the parties' experts.

Comparison of Prudhoe Bay End-of-Life Determinations

	CY 2007	CY 2008	CY 2009
PB Royalty Trust	2062[837]	2075[838]	2049[839]
Muni @ 100,000 bbl/d	2067[840]	2066[841]	2068[842]
Muni @ Economic Limit	2075[843]	2075[844]	2075[845]
SOA @ 150,000 bbl/d	2040[846]	2040[847]	2040[848]
SOA @ Economic Limit	2043[849]	2044[850]	2053[851]
Hoolahan – Initial	2026[852]	2033[853]	2021[854]
Hoolahan – Corrected	2046[855]	2053[856]	2032[857]

[835] MUN7-0001 at 3000.
[836] Tr. 8199-8202.
[837] MUN7-0001 at 3018 (Dec. 31, 2006).
[838] MUN7-0001 at 3009 (Dec. 31, 2007).
[839] MUN7-0001 at 3000 (Dec. 31, 2008).
[840] MUN7-4306 at 6.
[841] MUN7-4313 at 6.
[842] MUN7-4309 at 7.
[843] MUN7-0024 at 19.
[844] MUN7-0024 at 19.
[845] MUN7-0024 at 19.
[846] SOA7-7 at 18.
[847] SOA7-7 at 19.
[848] SOA7-7 at 20.
[849] SOA7-113 at 1.
[850] SOA7-114 at 1.
[851] SOA7-115 at 1.
[852] TO-07-0007.0151.
[853] TO-07-0007.0152.
[854] TO-07-0007.0152.
[855] TO-07-0092 (corrected) at 10.

504. **[CONFIDENTIAL – SEE SEALED ENVELOPE.]** [redacted]

[redacted]

505. Using a 100,000 bbl/d minimum throughput limitation, this Court finds that the total proven reserves as determined by the Municipalities is the best available estimate as of each of the lien dates except that this Court will remove the production forecast for Point Thomson for 2007 and 2009, for the reasons expressed above. For 2007, subtracting Point Thomson reserves from the Municipalities' reserves calculations results in an end-of-life of 2065 for that year. Because of the timing of Point Thomson production in the 2009 forecast, removing that unit from the production forecast does not affect the end-of-life calculation for 2009 – it remains at 2068.[863] For 2008, as noted above, the end-of-life based on a 100,000 bbl/d minimum capacity is 2066.

506. With Point Thomson removed from Mr. Platt's corrected reserves estimates for 2007 and 2009, the total proven reserves for each of the lien dates is as follows:

2007	7.812 billion barrels[864]
2008	7.759 billion barrels[865]
2009	7.077 billion barrels[866]

3. Application of the Economic Age-Life Method

a. TAPS' Effective Age

507. The first step in the application of the economic age-life method requires a determination of the effective age of the property. An effective age estimate should consider

[863] MUN7-4306 at 6; MUN7-4309 at 6.

[864] MUN7-4306 at 6 (8.198 less .386 = 7.812).

[865] MUN7-4313 at 6.

[866] MUN7-4309 at 7 (7.362 less 284.6 = 7.0774).

the condition and utility of the property. If a property has received typical maintenance, its effective age and its actual age may be the same.[867]

508. TAPS began transporting oil in the summer of 1977. Thus, as of the lien dates its actual age was between 30 and 32 years.

509. TAPS is well-maintained. In 2001, the Owners asserted in the right-of-way renewal application that "TAPS' physical life is considered virtually unlimited given the execution of appropriate surveillance, maintenance, repair, and replacement programs."[868] This Court finds that with continued prudent management of the pipeline and with routine investment in heaters should they be required, TAPS' physical life will extend for the duration of its projected economic life.

510. In recent years Alyeska has undertaken SR of the pumps. Alyeska also completed an upgrade of the ballast water treatment facility at the VMT during the lien years.[869] Such extensive renovations and upgrading of TAPS have a significant positive effect on the physical condition of TAPS.[870]

\\

\\

\\

\\

\\

\\

---

[867] *The Appraisal of Real Estate* at 412.

[868] MUN7-8511 at 5 (Owners' Right of Way Renewal Application).

[869] Tr. 3450 – 3456 (Stokes).

[870] *See The Appraisal of Real Estate* at 414.

511. Based on the foregoing, this Court will make a one-year adjustment to the actual age of TAPS as of each lien date to arrive at its economic age, for the same reasons such an adjustment was made in the 2006 tax year proceeding.[871] With that one-year adjustment, the economic age-life depreciation percentage for TAPS for each year is:

2007: (2007 – 1977.5 – 1.0) / (2065 – 1977.5) = 28.5 / 87.5 = 32.57%

2008: (2008 – 1977.5 – 1.0) / (2066 – 1977.5) = 29.5 / 88.5 = 33.33%

2009: (2009 – 1977.5 – 1.0) / (2068 – 1977.5) = 30.5 / 90.5 = 33.70%

512. This Court finds that using this effective age for TAPS reasonably captures all physical deterioration associated with the asset.

b. Additional Functional Obsolescence

513. Functional obsolescence is defined as obsolescence "caused by a flaw in the structure, materials, or design of the improvement when compared with the highest and best use of the most-effective functional design requirements at the time of appraisal."[872]

514. The use of an appropriate replacement cost study eliminates "many, but not all, forms of functional obsolescence such as superadequacies and poor design."[873] One measure of the functional obsolescence arising out of excess capital costs is the "difference between the reproduction cost and replacement cost."[874]

515. The Pro Plus replacement cost studies resolve much of TAPS' functional obsolescence associated with excess capital costs. Evidence of this may be found by comparing the Pro Plus cost study to TAPS' trended original reproduction cost based upon a

[871] *See also* Municipalities' Proposed Findings of Fact and Conclusions of Law ¶ 744.

[872] *The Appraisal of Real Estate* at 434.

[873] *The Appraisal of Real Estate* at 386.

[874] *Valuing Machinery and Equipment* at 88.

construction index such as Marshall and Swift.[875] SARB made such a comparison in 2009 and considered it a "valuable indicator."[876] Specifically, SARB noted that the Division's calculation of a $23.4 billion for 2009 based upon trending the original cost of TAPS using Marshall & Swift "compares favorably" with the $19.8 billion Pro Plus RCN adopted by SARB for that lien year.[877]

516. Functional obsolescence may also arise from the need to expend excess operating and capital expenses for the subject property compared with the most economical similar new property that has the equivalent utility.[878]

517. The 2007, 2008, and 2009 Pro Plus RCN cost studies propose a replacement pipeline that is very similar to what TAPS is likely to look like when the pipeline SR is complete.[879] Therefore, SARB reasonably relied on the projected costs in the actual SR pipeline plan to determine the necessary capital expenditures as well as excess operating costs to measure and calculate the current functional obsolescence.[880] SARB tax-adjusted these projected SR costs and discounted them to arrive at the following present value amounts as of each lien date of the functional obsolescence associated with completion of pipeline SR and the ballast water treatment facility projects: $242,639,688 in 2007,

---

[875] MUN7-0227 at 8 ("The Department relied on its policy of consistently applying the Marshall and Swift annual petroleum cost index to update original costs for all oil and gas properties in Alaska, which it has done for more than 30 years.")

[876] MUN7-0236 at 31 (SARB 2009 Decision).

[877] MUN7-0236 at 31 n.10.

[878] *Valuing Machinery and Equipment* at 88.

[879] However, the Pro Plus RCN has one more upgraded pump station than is currently planned on TAPS, which this Court has considered through scaling below.

[880] 2009 R. 124-25. These figures were derived from the Alyeska Long Term Plan.

$228,384,344 in 2008, and $250,150,655 in 2009.[881] The Court adopts these costs and finds that they would not otherwise be captured through the economic age-life methodology.

518. The Owners assert that additional adjustments for functional obsolescence are required to reflect excess operating costs and excess capital costs associated with TAPS when compared with the 30-inch Stantec pipeline.[882] However, as detailed above, this Court has found that the 30-inch Stantec RCN pipeline is not a proper replacement property for TAPS. Therefore, a comparison of the operating costs between the existing TAPS and the Stantec RCN is not a proper measure of TAPS' functional obsolescence.

519. The Owners have also included the future costs of heaters as a functional obsolescence deduction. But to date, the Owners have made no decision as to the number, type, or manufacturer of heaters nor have any bids to acquire and install heaters been requested.[883] While some amount of heaters seem likely to be required at some indeterminate point in the future, heaters were not required at all for the operation of TAPS during the lien years or today. The Owners failed to establish by a preponderance of the evidence that a functional obsolescence deduction for the future cost of heaters was warranted during the lien years. The cost, timing, and precise needs are too speculative to be considered when determining the economic value of TAPS from 2007 to 2009.

520. The Owners also seek functional obsolescence deductions for projected costs to replace the ballast water treatment facility, install internal floating roofs on the crude oil

---

[881] *See* MUN7-0234 at 12; MUN7-0235 at 18; R. 10669 (2009 SARB). *See also* MUN7-0035 at 51, 55, 59.

[882] TO-07-0004.0074-76 (functional obsolescence deduction for excess operating expenses); TO-07-0004.0076 (functional obsolescence deduction for excess capital expense).

[883] TO-07-0004 at 75.

storage tanks, and modify the vapor recovery systems at the VMT.[884] But the evidence at trial was inconclusive as to whether this list of projects would ever be sanctioned or built. Steven Schudel of Alyeska explained the status of potential reconfiguration at the VMT. He indicated that Alyeska was studying its options and awaiting an EPA ruling before determining how to proceed.[885] He testified that option one "would retain the existing facilities and then you do whatever upgrades you have to do to comply with the [as yet un-promulgated EPA] regulations."[886] This Court finds that an adjustment for functional obsolescence for additional projects that may or may not be undertaken at the VMT is unwarranted for the 2007 to 2009 tax years.

521. This Court finds persuasive the Board's determination on this issue in 2007, when the Owners put forward a list of proposed adjustments for functional obsolescence due to alleged inefficiencies in TAPS. In rejecting those adjustments, the Board held:

> The Board concluded that, as of the assessment date, the timing and need for changes to the TAPS that form the basis for the Owners' claims for the need to account for additional obsolescence due to low flow conditions and other factors are too speculative to require an additional downward adjustment to the TAPS value. The further that possible impacts on value of the TAPS are pushed out into the future, the less these future contingencies, such as adding additional reserves to future throughput or incurring additional costs, are likely to impact current value. The Board agreed with the Municipalities and the Division that an assessor should generally wait at least until a property owner has definite plans to incur specific costs before the assessor gives those projected costs much weight in making an estimate of value.[887]

---

[884] *See, e.g.,* T0-07-.0004.0076 (valuation as of Jan. 1, 2009).

[885] Tr. 1349-1351 (Schudel).

[886] Tr. 1350 (Schudel).

[887] MUN7-0234 at 19-20. *See also* Amended Decision ¶ 433.

522. This Court also notes that appraisal theory directs that curable items of functional obsolescence be deducted from the RCN before the age-life ratio is applied to the RCN, and not after.[888]

c. Additional Economic Obsolescence

523. Economic obsolescence, or external obsolescence, is the loss of value of a property caused by factors external to the property.[889]

i. Scaling

524. This Court applied an economic age-life depreciation analysis in the 2006 tax year, and also held that an additional $932 million of depreciation for economic obsolescence was warranted. Specifically, this Court held that "[w]hile TAPS is required to have a design capacity of at least 1.1 million bbl/d, the fact that capacity is not all being used to transport affiliated oil reduces the utility and value of TAPS as of the lien date."[890]

525. When depreciating using the economic age-life method, this Court continues to find that application of scaling to TAPS is warranted because the economic age-life method would not otherwise capture all of the depreciation in TAPS that is attributable to its current superadequacy in relation to the proven reserves that are presently available to be transported on TAPS. Thus, while this Court has determined that an RCN must be of equivalent utility to TAPS – both in terms of the ability of the post-SR pumps to transport 1.1 million bbl/d and in terms of the 48-inch pipeline's and VMT's ability to handle capacities of up to 2.1 million bbl/d – that determination does not mean that this Court must or should disregard the fact that during the lien years, the throughput on TAPS was far less than those

[888] *The Appraisal of Real Estate* at 422.

[889] *Valuing Machinery and Equipment* at 67. *See also The Appraisal of Real Estate* at 391-92.

[890] Amended Decision ¶ 439.

capacity levels such that the economic value of TAPS was less that it would have been had TAPS been transporting 2.1 million bbl/d during the lien years. Not to apply a scaling factor in these circumstances would result in an improper valuation of TAPS, particularly since the statute directs that economic value be determined with due regard to proven reserves, and not probable or potential reserves.

526. The Municipalities also assert that scaling physical facilities based upon capacity that is not obtainable without the additional expense of DRA is not appropriate. They assert that to do otherwise would scale the capacity created by DRA, which is an operating expense rather than a capital item. Thus, they assert that if scaling is applied now or in the future, it should only be calculated based only upon TAPS' actual mechanical capacity of 760,000 bbl/d.[891]

532. This Court has given careful consideration to the appropriate application of scaling to TAPS so as to account for its economic obsolescence that results from its underutilization during the lien years. SARB has applied the scaling approach utilized by the Division in each of the lien years. Under that approach, an underutilization ratio was obtained by dividing the average daily throughput into the legally required capacity of 1.1 million bbl/d, using a scale factor of .45. The basis for the scale factor is found in a BP-generated analysis.[892]

533. Neither of the appealing parties met their burden of proof that the .45 scaling factor employed by the Division and accepted by the Board was improper.

---

[891] Municipalities' Proposed Findings of Fact and Conclusions of Law ¶ 791.

[892] *See* 2009 R. 6505-06.

534. This Court has discussed in detail when addressing the appropriate RCN to apply to TAPS that to be of equal utility to TAPS, an RCN must include the same design capacity that is currently specified for the pipeline and the VMT – 1.42 million bbl/d. Thus, while Pro Plus has asserted that its design basis for its RCN is 1.1 million bbl/d, the evidence demonstrates that capacity is derived from the number of installed pumps. The Pro Plus RCN 48-inch mainline pipe has the same capacity as the existing TAPS 48-inch pipeline, and the actual tank capacity at the existing TAPS VMT is comparable to the Pro Plus VMT, which is a design capacity of 1.42 million bbl/d. While this Court does find merit in the Municipalities' assertion that scaling to the 2.1 million bbl/d capacity achieved with DRA would be inappropriate, a scaling adjustment for underutilization of the 48-inch pipe and the VMT based on TAPS' existing capacity of 1.42 million bbl/d is warranted. The Division and SARB's use of 1.1 million bbl/d design as the denominator for those components of TAPS resulted in an improper valuation.

535. With respect to the pumps, the Municipalities have asserted that scaling, if used at all, should be based against the mechanical capacity of the existing TAPS of 760,000 bbl/d. But given that the Pro Plus RCN has one more SR pump station than the existing TAPS, this Court finds that scaling the pumps to a 1.1 million bbl/d capacity is warranted.[893]

536. The other applicable inputs to make this scaling deduction are as follows:

- Using the Pro Plus RCN, an average of approximately 8.7% of the direct costs are associated with the pump stations and meter stations during the three lien

[893] *See generally* TO-07-0063.

years. The balance of the costs, or 91.3 %, is associated with the 48-inch mainline pipe and the VMT.

- The DOR projected throughput for TAPS during each of the lien years was as follows:[894]

  2007 – 740,000 bbl/d

  2008 – 731,000 bbl/d

  2009 – 691,000 bbl/d

- A scaling factor is an exponential calculation, and thus results in less of a reduction than would occur with a percentage adjustment. Applying a .45 scaling factor to the above figures would result in the following additional percentage adjustments to the RCN after application of the additional functional obsolescence and the economic age-life calculation:

2007	Pipeline & VMT	25.4%
	Pump Stations	16.3%
2008	Pipeline & VMT	25.8%
	Pump Stations	16.8%
2009	Pipeline & VMT	27.7%
	Pump Stations	18.9%

ii. No Additional Economic Obsolescence Adjustment Is Warranted

532. The Owners assert that a significant additional economic obsolescence adjustment is warranted because TAPS is a regulated pipeline, and the effects of that regulation lower the pipeline's value.[895] But they have produced no credible evidence that

[894] MUN7-0018 at 13, 20, 27.

[895] TO-07-0004 at 70-71.

establishes that the regulated status of TAPS has had any impact on the economic value of TAPS. This Court finds that TAPS would operate in much the same manner regardless of its regulated status. Tariff income that the Owners earn for shipping another producer's oil is in addition to the primary value that TAPS has for each Owner – the shipment of that Owner's affiliated oil.

527. The evidence persuasively demonstrated that TAPS was profitable as of each of the lien dates, and that it would be reproduced if it did not presently exist. There were over seven billion barrels of proven reserves remaining on the North Slope as of each lien date for 2007, 2008, and 2009 – an amount comparable to the estimated 9.6 billion barrels of proven reserves when TAPS began operation in 1977. The New York Supreme Court, Appellate Division has held that "[w]hile an allowance for economic obsolescence may be made when the property is not worth the reproduction cost, depending upon the earning capacity after production, it cannot be made in these circumstances where petitioner is profitable and the property would be reproduced. That petitioner is a regulated [pipeline] utility does not alter this conclusion."[896]

528. The Owners' appraisal experts used what is termed an income shortfall method in an effort to calculate the percentage return differential between the projected tariff rate and a hypothetical unregulated rate, which was then discounted to present value.[897] Using this approach, the Owners' appraisal expert, Mr. Remsha of American Appraisal, concluded that the income shortfall due to a buyer's inability to reset the rate base and collect a higher return is approximately $1,030,000,000 in 2007, $845,000,000 in 2008, and

[896] *Tenneco, Inc. v. Town of Cazenovia,* 104 A.D.2d 511, 514 (N.Y. App. Div. 1984).

[897] TO-07-0004 at 86, 115, 130.

$730,000,000 in 2009.[898] Terming that amount to constitute economic obsolescence, American Appraisal concluded that the value of TAPS under the RCNLD approach was identical to the value it concluded under the income approach of $1.1 billion for 2007, $1.2 billion for 2008, and $1.3 billion for 2009.

529. This Court rejected this same application of an income shortfall method in the 2006 tax year proceeding that was advanced then by the Owners' expert appraiser, Ms. Spletter.[899]

530. Mr. Remsha acknowledged that if economic obsolescence in the form of income shortfall is applied, it makes no difference whether the RCN is $10 billion or $100 billion – the RCNLD would be identical using the income shortfall approach.[900] Similarly, he testified that it did not matter whether the Pro Plus cost study or the Stantec cost study was used, the RCNLD would be the exact same result. Other appraisers persuasively testified that the effect of applying an income shortfall method is to eliminate the independent value of the cost approach by altering it to an income approach.[901]

531. Aside from the conceptual circularity of the income shortfall approach, its particular application to TAPS is inappropriate for the same reasons that this Court has rejected the tariff income approach.[902] Since tariff income is not a driver of the economic

---

[898] TO-07-0004 at 86, 115, 130.

[899] Amended Decision ¶¶ 452-56.

[900] Tr. 11914-15 (Remsha). *See also* Reilly Dep. 133 (June 2, 2011).

[901] Tr. 908-09 (Eyre); Tr. 12365-66 (Goodwin).

[902] *See* Tr. 12365-66 (Goodwin).

value of TAPS, its application to the cost approach is inappropriate. Mr. Eyre's testimony with regard to this topic was particularly helpful to the Court.[903]

532. The Owners did not present any new law or facts different from the 2006 tax year proceeding to support their use of a capitalized income shortfall method. This Court finds, as it did in the 2006 matter, that such a method should not be applied to determine economic obsolescence of TAPS.[904]

533. The Western State Association of Tax Administrators ("WSATA") Appraisal Handbook rejects the income shortfall method:

> A few appraisers attempt to measure obsolescence by comparing a company's actual earnings with the theoretical earnings that should have been achieved by the company with the assets on hand if they were earning a fair return on cost. This method is an improper variation of method often used for individual properties, where it can be demonstrated that the subject property is not technologically capable of producing as much operating income (cash flow) as new replacement property. When used to compare company earnings with theoretical company earnings, the method simply forces the cost approach to agree with the capitalized earnings approach.[905]

The WSATA Appraisal Handbook has wide acceptance by the approximately 35 states that do unit valuations and has undergone a comprehensive peer review process.[906]

\\

\\

\\

\\

[903] Tr. 908-09 (Eyre).

[904] Amended Decision ¶¶ 462-64.

[905] WSATA Appraisal Handbook at 31 (Aug. 1989).

[906] Tr. 11123-24, 11141-44 (Eyre).

534. Several appellate courts have also recognized that the income shortfall method is circular.[907] As the New Jersey Supreme Court explained in *Transcontinental Gas Pipe Line Corp. v. Bernards Township*, a depreciated regulated pipeline has a value distinct from its tariff income that derives from its use:

> Under the cost approach as it applies to special purchase property, the costs of a third person in acquiring the property is not the relevant inquiry; the very reason the cost approach is being utilized is that the property is so uniquely suited to its current use and user that a market sale to a third person is not an accurate indication of its value. Rather, the determination made in applying the cost approach is how much would a prudent person pay to replace the property. Since the people with the greatest interest in replacing special purchase property are the people for whom it was designed and built, and, in addition, are the people who must assume the cost of property taxation, the relevant question to ask in applying the cost approach to utility property is how much the ratepayers would pay to replace the property.[908]

535. In *Transcontinental*, the New Jersey Supreme Court also held:

> The purposes of FERC regulation and ad valorem property taxation are drastically different: FERC is primarily concerned with ensuring that investors receive an adequate return on the property that has been invested. For such purposes, the original value of the property invested is an appropriate measure of value. For property tax purposes, however, it is necessary to determine the present cost of replacing the property. Under the cost approach, this is assumed to be the value of the property to the ratepayers, reflecting increases in construction costs, the current demand of consumers, availability and cost of alternate energy sources, and other factors. FERC's regulatory system reflects these factors only as of the time an asset enters the rate base; it makes no attempt to update them until an asset's functional lifespan is reached and it is eventually replaced at

[907] *See United Tel. Co. of Nw., Inc. v. Dep't of Revenue*, 770 P.2d 43, 51 (Or. 1989) ("[a]djusting one approach to make it rely on the result or the same indication of value as another approach effectively eliminates a relevant perspective from consideration); *Delta Air Lines, Inc. v. Dep't of Revenue*, 984 P.2d 836, 849 (Or. 1999); *Tenneco*, 104 A.D.2d at 514 ("It appears then that [the taxpayer's expert's] concept of economic obsolescence is nothing more than an attempt to convert the RCNLD approach into an income capitalization approach. This is not permissible."); *see also Tenn. Gas Pipeline Co.*, 766 A.2d at 675-76; *Transcont'l. Gas Pipe Line Corp. v. Bernards Twp.*, 545 A.2d 746, 763 (N.J. 1988).

[908] *Transcont'l. Gas Pipe Line*, 545 A.2d at 758 (citations omitted). *See also* Amended Decision ¶ 459.

current costs. Since depreciated original cost fails to reflect the value of all of the interests in utility property and undervalues those it does recognize, we decline to accept it as a true measure of a utility property's worth.[909]

536. Similarly, the Montana State Tax Appeal Board ("STAB") rejected the analysis of one of the Owners' experts in this case: "STAB rejected [Thomas] Tegarden's income shortfall approach because, among other reasons, it failed to account for income from properties that PacifiCorp had purchased with deferred income taxes" in 2005.[910] STAB also rejected the income shortfall method for its inaccuracies.[911] In 2011, the Montana Supreme Court found that the STAB was entitled to deference regarding its determination that there was no economic obsolescence when the owners' entire case for economic obsolescence was premised on the income shortfall method.[912]

537. An income shortfall adjustment is not appropriate for determining the full and true value of TAPS during the lien years at issue. The Owners failed to establish that the Division and SARB erred in refusing to apply the income shortfall method to determine economic obsolescence. Rather, if the income shortfall method was applied based on tariff income, the RCNLD valuation would no longer reflect the "full and true" economic value of TAPS as a critical component of the integrated ANS production and transportation system.

538. The record does not support the proposition that the regulatory status of TAPS negatively affects its economic value. Instead, the Court is fully persuaded that TAPS would continue to operate in much the same fashion as it does today whether it was subject to

[909] *Transcont'l. Gas Pipe Line*, 545 A.2d at 760 (citations omitted). *See also* Amended Decision ¶ 460.

[910] *See Pacific Corp. v. State*, 253 P.3d 847, 848, 854-55 (Mont. 2011).

[911] *Pacific Corp. v. State*, 253 P.3d at 855.

[912] *Pacific Corp. v. State*, 253 P.3d at 854-55.

regulation or not. Each Owner's affiliated producer would be likely to continue to transport its oil on its affiliated pipeline space and would continue to pay the costs associated with such transportation. The record supports the proposition that the regulatory status of TAPS may positively shape its economic value. For example, the regulation of TAPS permits the Owners to share the costs associated with the operation of TAPS and realize a profit from independent shippers.[913] Dr. Cicchetti referred to this profit opportunity as the "icing on the cake."[914] Further, the regulatory status of TAPS also increases the value of each integrated enterprise by permitting each producer to deduct the tariff rate when calculating its royalty and production taxes to the State of Alaska.[915]

539. This Court has given careful consideration to the fact that TAPS is regulated by both FERC and the RCA, and has concluded that the Owners have failed to demonstrate that the value of TAPS for purposes of ad valorem property taxation under AS 43.56 is negatively impacted by either its regulatory status or its current or projected tariff income. No additional adjustment for economic obsolescence is warranted.

C. RCNLD Conclusion of Value

540. This Court has found that the replacement cost new estimate of value for TAPS is $17.645 billion in 2007, $19.324 billion in 2008, and $19.137 billion in 2009. Then functional obsolescence that is not captured under the economic age-life depreciation is deducted in the amount of $242,639,688 for 2007, $228,384,344 for 2008, and $250,150,655 for 2009, as well as the value of the land and ROW of $194 million each year.

---

[913] Tr. 8299-8301 (Cicchetti).

[914] Tr. 8300 (Cicchetti).

[915] Tr. 8252-53 (Cicchetti); Tr. 7721-23 (Toof).

From there, economic age-life depreciation based on an end-of-life calculation is applied of 32.57% for 2007, 33.33% for 2008, and 33.70% for 2009. Then an additional deduction for economic obsolescence based on scaling is made in the amount of $2.856 billion for 2007, $3.152 billion for 2008, and $3.338 billion for 2009. Then the value of the land and the right-of-way are added back. The result is a total RCNLD of $8.941 billion for 2007, $9.644 billion for 2008, and $9.249 billion for 2009.

VIII. THE INCOME APPROACH

A. The Integrated Income Approach to the Valuation of TAPS

541. The income approach determines the value of a property based upon the expected future benefits to its owner.[916] The principle of anticipation is fundamental to the income approach.[917]

542. The income approach is generally used in valuing commercial business and properties that are bought and sold by investors because of the income they generate. The approach values the entire business entity. The income approach is not widely used by machinery and equipment appraisers because of "the difficulties in determining income that can be directly related to a specific asset, the concern for reliability of income forecasts, and a multitude of variables involved in this valuation approach."[918]

---

[916] *Valuing Machinery and Equipment* at 159-60, 571.

[917] *The Appraisal of Real Estate* at 446.

[918] *Valuing Machinery and Equipment* at 159-60.

543. Since 2005 the Division and SARB have considered the income approach for TAPS multiple times, but have rejected it each time as an unreliable indicator of economic value.[919]

544. When applying the income approach to a property that is a part of an integrated economic enterprise, an appraiser may consider the income generated by the entire integrated economic enterprise and then allocate a portion of that income and the resulting value back to the part of the integrated enterprise for which a value is to be determined.[920] This integrated income approach is a form of unit valuation which is defined as the "evaluation of a group of integrated assets that are functioning as an economic unit."[921] Standard appraisal practice allows a unit to be composed of regulated and non-regulated properties.[922]

545. When deciding the proper unit to value, appraisers look at the integrated use of the business property.[923] In particular, an appraiser looks to the physical, functional, and economic integration of the properties to determine the proper unit.[924] In the case of TAPS, its integration with upstream properties makes the proper unit to value one that is composed of upstream and midstream Alaska properties.[925]

546. Brent Eyre, on behalf of the Municipalities, employed a discounted cash flow income approach to value the integrated economic unit of which TAPS is a part at $40.2

[919] Tr. 12417-18 (Hoffbeck).

[920] Tr. 11123 (Eyre).

[921] Tr. 11125 (Eyre).

[922] Tr. 11125 (Eyre).

[923] Tr. 11128 (Eyre).

[924] Tr. 11128-29 (Eyre).

[925] Tr. 11128-31, 11134 (Eyre).

billion in 2007, $44.2 billion in 2008, and $50.4 billion in 2009.[926] Dr. James Smith, on behalf of the Owners, testified that Mr. Eyre's unit value of the integrated ANS enterprise should be reduced by slightly less than 10% for each year, for a value of $36.4 billion in 2007, $41.1 billion in 2008, and $46.0 billion in 2009.[927]

547. A commonly used factor for allocating unit value is invested cost, wherein the invested cost of the property subject to assessment is divided by the total amount of invested costs in the unit as a whole.[928] After adjusting invested costs for inflation, Mr. Eyre determined that the allocated value of the whole unit to TAPS was approximately $8.8 billion (21.9%) in 2007, $9.6 billion (21.7%) in 2008, and $10.7 billion (21.2%) in 2009.[929]

548. This Court was not persuaded that the integrated income approach should be relied upon to determine the economic value of TAPS for the lien years at issue, particularly where, as here, a comprehensive replacement cost new study has been accepted as modified by the Court, such that a considered application of the cost approach can be relied upon. The integrated income approach is more dependent upon volatile assumptions related to reserves, oil prices, and allocation than the cost approach. However, Mr. Eyre's valuation is a useful frame of reference and supports the assessed valuation of TAPS as determined by this Court for the lien years at issue. It also demonstrates that the tariff income approach advocated by the Owners fails to capture all elements of TAPS' economic value.

[926] Tr. 11137 (Eyre).

[927] Tr. 12073, 12082 (Smith).

[928] Tr. 11137-38 (Eyre).

[929] Tr. 11138-39 (Eyre).

B. The Tariff Income Approach Does Not Capture the Full and True Value of TAPS Under AS 43.56.060(e)(2)

549. As in the 2006 tax year litigation, the Court finds again that tariff income is not the primary driver of the economic value of TAPS under AS 43.56. As SARB has held, and as this Court has previously discussed in these findings, TAPS was not built or operated for tariff income, but to monetize the vast ANS reserves of the producer oil companies by bringing those reserves to market.[930] In this regard Mr. Coulson, the President of BP Pipelines (Alaska) Inc. and the Chairman of the Owners' Committee for TAPS at the time, testified as follows:

> Q: It's fair to say that TAPS was built by the producers?
>
> THE WITNESS: Yes.
>
> Q. And it's fair to say that TAPS was built - that the economic driver was the integrated economics of bringing the Alaska North Slope oil to market?
>
> THE WITNESS: As I understand the history of TAPS, and indeed of most basin-opening developments, it's usually the resource owner that has to make the infrastructure development happen because of the risks associated with an undertaking like that.
>
> Q. And the reason that the resource owner takes those risks is in order to monetize the resource and bring it to market, correct?
>
> THE WITNESS: Yes.[931]

550. The evidence also demonstrated that each Owner's interest in TAPS is a component of an integrated economic enterprise.[932]

---

[930] Tr. 7729-30 (Toof); Tr. 8931 (Grasso) ("[T]he Owners aren't in the market to build a pipeline for its tariff income, but to get the – but to monetize the reserves on the North Slope."); Tr. 8482 (Brown); Tr. 8546-47 (Sullivan); Tr. 8249-50 (Cicchetti). *See also* Amended Decision ¶¶ 94, 471, 478.

[931] MUN7-0001 at 3767 (Coulson Dep.).

[932] Tr. 8249-65 (Cicchetti); Tr. 8539-40; 8546-8547 (Sullivan); Tr. 8891-92, 8934 (Grasso).

551. In contrast to Mr. Eyre's approach, which considered the income from the entire integrated economic enterprise, the Owners assert that the tariff income from TAPS, and only that income, is the appropriate proxy to capture the entire economic value of TAPS.[933] The Owners' reliance upon the tariff income approach fails to recognize that TAPS was built, is operated, and would be replaced at an estimated cost of approximately $19 billion if it were not in existence, not because of a desire to realize tariff income, but because of the overwhelming economic value arising from its highly integrated use for transporting ANS production to market.[934]

552. The Owners' position that the tariff income is a primary driver of the economic value of TAPS is at odds with the extensive system of crude oil pipelines on the ANS that are fully integrated with North Slope production and fully maintained but have no tariff income associated with their operation.[935]

553. In valuing TAPS for ad valorem purposes, the Department applied the cost approach without any reliance on the tariff income from 1977 to 1985, and then beginning again in 2005 to date.[936] In 2001, the Department used a tariff-based income approach. For all the other years in between, the record suggests that the Department apparently relied upon a negotiation process that considered different valuation approaches including the tariff income approach, but many details of those negotiations have not been made available to this Court by either the Department or the Owners.[937]

[933] TO-07-0004 at 0096, 0102, 0103, 0105.

[934] Tr. 8249-65, 8299-8302 (Cicchetti); Tr. 8480-81 (Brown); Tr. 8546-47 (Sullivan); Tr. 8891-92 (Grasso).

[935] Tr. 7851-52 (Marks); Tr. 12682-83 (Goodwin); Tr. 2725-26 (Falcone); Amended Decision ¶ 476.

[936] Tr. 12691 (Goodwin); 2009 R. 483-84; Amended Decision ¶ 477.

[937] Tr. 6816-17 (Greeley); MUN7-0234 at 4; Tr. 12419-20 (Hoffbeck).

554. The unique ownership structure of TAPS, the almost complete dependency of TAPS Owners on their affiliated and parent companies to build, operate, and improve TAPS, the use of TAPS by each Owner as part of its vertically integrated enterprise, and the history of ownership interests in TAPS all indicate that tariff income is not determinative of the economic value of TAPS.[938] The sheer magnitude of the economic value realizable from the use of TAPS to monetize ANS reserves makes it far more likely than not that TAPS would continue to operate much as it does today or in 2007, 2008, or 2009, even if there was no tariff income at all.[939]

555. The tariff income approach incorrectly assumes that there would be a hypothetical buyer interested solely in the tariff income of TAPS to whom the TAPS Owners would agree to sell their interests. But the sales of ownership interests in TAPS have been to buyers that subsequently used TAPS as part of their integrated operations.[940] The weight of the evidence demonstrates that there is not nor ever has been a market for TAPS based on its tariff income.[941] This is not unexpected considering the economic realities of developing isolated crude oil fields in Alaska. This Court finds that the tariff income approach proposed by the Owners is based on a fundamentally wrong premise of value, as it assumes that there is a willing buyer and a willing seller of TAPS based solely on its tariff income as a stand-alone investment.

[938] Tr. 8255-57 (Cicchetti).

[939] Tr. 12170 (Marks) (in response to the question of whether the TAPS Owners would operate TAPS even if they were not allowed tariff recovery, Mr. Marks responded, "I believe they would.").

[940] Tr. 8878 (Marchitelli); Tr. 12682 (Goodwin); Huck Dep. at 147-49 (May 2, 2011).

[941] Tr. 8891 (Grasso); Tr. 8547 (Sullivan) (tariff income is not the driver of investments; access to the ANS reserves is the driver of TAPS investment decisions); MUN7-0001 at 3766-3767 (Coulson Dep.) (in response to the question whether Mr. Coulson was aware of any pipeline in Alaska that was built by a nonproducer, Mr. Coulson responded, "I am not aware of any.").

556. Tariff income is a regulatory, not an economic construct that has little place in determining the economic value of a pipeline used primarily for affiliated transportation.[942] Likewise, the value determination of TAPS for ratemaking purposes is not the same as the value determination of TAPS for ad valorem tax purposes.

557. Several other courts have recognized the distinction between ratemaking and the determination of a property's value for ad valorem taxation purposes, both with respect to pipeline properties,[943] as well as other types of properties.[944] As the New Jersey Supreme Court in *Transcontinental Gas Pipe Line Corp. v. Bernards Township* explained:

---

[942] Tr. 8293-8294 (Cicchetti).

[943] *See Questar Pipeline v. Utah State Tax Comm'n*, 850 P.2d 1175, 1178 (Utah 1993) (property tax appraisers of gas pipelines were within their rights when, after taking the consequences of FERC rate regulation into consideration, they did not alter their final opinions when adopting a method of valuation inconsistent with the FERC rate base value); *Transcont'l. Gas Pipe Line Corp.*, 545 A.2d 746 (1988) ("Courts in other states have long recognized a definite distinction between the valuation of public utility property for ratemaking purposes, determined pursuant to statutes applicable thereto, and the valuation of the same property pursuant to different statutes for ad valorem tax purposes.") (internal quotations omitted); *Mich. Wis. Pipe Line Co. v. Iowa State Bd. of Tax Rev.*, 368 N.W.2d 187, 191-192 (Iowa 1985) (board of tax review did not err in failing to set property tax of gas pipeline in a manner consistent with its FERC rate base even when evidence was offered that FERC rate base determined value for sales of comparable pipelines); *Mobil Pipeline Co. Rohmiller*, 522 P.2d 923, 936-937 (Kan. 1974) ("This issue, the regulations of earnings computed on a 'rate base,' was the major thrust of the public utility in attacking the assessment of its Kansas property in *Northern Natural Gas Co. v. Dwver*, [492 P.2d 147 (Kan. 1971)]. The Court there recognized a definite distinction between the valuation of public utility property for rate making purposes, determined pursuant to statutes applicable thereto, and the valuation of the same property pursuant to different statutes for ad valorem tax purposes.").

[944] *Matter of Long Island Lighting Co. v. Assessor for Town of Brookhaven*, 246 A.D.2d 156, 165 (N.Y. App. Div. 1998) ("[W]e note that we have previously held that a utility's rate base is an inappropriate factor to consider in the assessment of specialty property."); *S. Bell Tel. & Tel. v. Markham*, 632 So.2d 272 (Fla. Dist. Ct. App. 1994) (appraiser must consider effects of government regulation, *i.e.*, the rate base that controls earnings, under the controlling statute, but such regulation need not be determinative of property tax value), *Cent. Me. Power v. Town of Moscow*, 649 A.2d 320, 325 (Me. 1994) (The limit on return that an owner of dam utility property may earn on its investment because of its rate base is a factor that should be taken into account in valuation but is "emphatically not automatically determinative of the facility's just valuation" for property tax purposes.); *Consumers Power Co. v. Big Prairie Twp.*, 265 N.W.2d 182 (Mich. Ct. App. 1978) (the ad valorem assessing tax tribunal did not err in utilizing the adjusted depreciated reconstruction-cost method in assessing a dam rather than using the depreciated net cost value used by the FPC for ratemaking purposes), *superseded by statute; Pub. Serv. Co. of N.H.*, 377 A.2d at 125-126 ("[E]ven though net book value (original cost less depreciation) provides the rate base upon which plaintiff's rate of return is calculated, the value of the plant for tax purposes and the value for rate-making purposes need not be the same.") (internal quotations omitted); *Town of Barnet v. New England Power Co.*, 296 A.2d 228 (Vt. 1972) ("Fair market value should not rely upon one criterion and the values shown by the various methods of valuation

> [T]he fact that FERC's regulatory scheme includes a value determination for its own [ratemaking] purposes does not bind municipalities to that figure for the purpose of ad valorem property taxation.[945]

558. For the foregoing reasons, this Court finds that a valuation of TAPS based upon its tariff income would not capture the full and true value of TAPS.

C. Tariff Income Is Not a Reliable Indicator of Economic Value

559. Even if tariff income was relevant to determining the economic value of TAPS, the projected future tariff income advanced by the Owners has not been demonstrated to be sufficiently reliable to determine the economic value of TAPS.

560. Under rate regulation, an owner is entitled to recover operating costs, a return of investment through a depreciation deduction, and a reasonable return based on unrecovered investment. Essentially, the return or profit from the tariff income is based entirely upon the unrecovered investment or rate base. In the case of TAPS, several experts testified that the original investment in TAPS has already largely been fully recovered through accelerated depreciation.[946] Accordingly, the current return under the tariff income approach does not accurately reflect the economic value associated with the original investment in TAPS, as there is virtually no rate base or return under the tariff income approach associated with the majority of the existing TAPS' facilities.[947] For

---

should be weighed and not averaged by the board. The bases of valuation for taxation purposes and for rate-making have been uniformly recognized as different.") (citations omitted).

[945] 545 A.2d 746, 758 (N.J. 1988) (citation omitted); *County of Wayne v. Mich. State Tax Comm'n*, 682 N.W.2d 100, 126 (Mich. 2004); *Tenn. Gas Pipeline Co. v. Town of Hudson*, 766 A.2d 672, 675-676 (N.H. 2000) (holding that replacement-cost method, not the net-book-cost method, was the proper method for valuing the pipeline company's FERC-regulated property). *See also* Amended Decision ¶ 81.

[946] Tr. 1212 (Marks) (testifying that "by the mid 90s it shows about 95 percent of TAPS had been depreciated under TSM. By the late '90s, essentially 100 percent of TAPS had been depreciated under TSM"). *See also* Tr. 7715-16 (Toof); Tr. 12421-22 (Hoffbeck); Tr. 12689-88 (Goodwin).

[947] Tr. 12687-88 (Goodwin).

example, the original investment associated with the mainline pipe and VMT is almost fully recovered, such that there is little to no rate base associated with the economic contribution of either the mainline pipe or the VMT to the ongoing operations of TAPS.[948] The current return on TAPS only reflects the additional investment associated with recent capital expenditures on TAPS such as the SR project.[949] Thus, an income approach based on tariff income as advanced by the Owners would result in TAPS not being taxed at its full and true value.[950]

561. Historically, regulatory disputes concerning TAPS' tariff rates have most often been resolved by settlement among the parties rather than by a substantive determination by FERC or the RCA.[951] The settlement that has governed TAPS' tariff rates for the majority of the time it has been in service has been the TAPS Settlement Agreement ("TSA"). The TSA contained a complex and unique rate methodology referred to as the TSM. Both the State and the TAPS Owners supported the TSA. An Explanatory Statement by the State of Alaska and the Department of Justice in support of the settlement stated, "Alaska and DOJ believe that as a settlement, the tariff stream produced by the TSM is a fair and reasonable attempt to achieve a tariff profile that will encourage economically efficient exploration of North Slope petroleum resources."[952]

---

[948] Tr. 12421-22 (Hoffbeck); Tr. 12687-88 (Goodwin).

[949] Additions to the property used by a carrier to provide service will increase the rate base, the return on the rate base, and consequently the tariff income. In the case of TAPS, although the TAPS Owners made additional capital expenditures for TAPS in the SR project, the prudency of those expenditures is being challenged in the current joint rate proceeding before FERC and the RCA, and the rate effect of the SR expenditure is at this time unknown.

[950] Tr. 12421-12422 (Hoffbeck); Tr. 12687-12688 (Goodwin).

[951] *See, e.g.*, Tr. 8933 (Grasso).

[952] TO-07-0031.0119.

562. The RCA found that under the TSM, between 1977 and 1996, the TAPS Owners collected, in 1997 dollars, $13.5 billion more than would have been collected under the current rate methodology used by the RCA to set rates on TAPS.[953] Nevertheless, the TSM was approved by FERC.[954]

563. Settlements are approved by FERC under a fair and reasonable standard and in the public interest standard and not under a just and reasonable standard.[955] FERC may also approve black-box settlements under which the rate is known but not the methodology used to calculate the rate.[956] One of the Owners' regulatory experts, Dr. Toof, acknowledged that "settlement rates are a beast unto themselves."[957]

564. In 2005 and 2006, after the TSM had expired, FERC set just and reasonable rates under the Opinion No. 154-B methodology for 2005 of $1.92 and for 2006 of $2.02.[958] Under FERC doctrine, however, the last "clean rate," meaning the last unprotested TSM rate for 2004, was used as the floor for refunds for 2005 and 2006.[959] That rate was from $3.00 to $3.20.[960] The TAPS Owners also filed for rate increases in 2007 and 2008, which were

---

[953] MUN7-0001 at 1140, 1274, 1513-1516 (excerpts from RCA Order No. 151, Nov. 27, 2002) ("We now compare the past annual DOC revenue requirements . . . with the past annual TSM revenue requirements. Exhibit 7, Schedule 2 reveals that TSM has, on a cumulative basis, provided the Carriers with an opportunity to recover $9.9 billion more than their costs as determined by the DOC revenue requirements. In 1997 dollars, the net present value of the cumulative stream of revenue requirement difference is $13.5 billion . . . ."); Tr. 8496-8500 (Brown); Tr. 8542-43 (Sullivan) ("The underlying principles in that TAPS Settlement Agreement provided for the highest return on any pipeline I have ever done an analysis on.").

[954] Tr. 7292 (Kelly).

[955] Tr. 7292 (Kelly).

[956] Tr. 7293 (Kelly).

[957] Tr. 7730 (Toof).

[958] *BP Pipelines (Alaska) Inc.*, 125 FERC ¶ 61,215 at ¶ 103, 115 (2008).

[959] *BP Pipelines (Alaska) Inc.*, 125 FERC ¶ 226 (2008) (Op. No. 502).

[960] *BP Pipelines (Alaska) Inc.*, 127 FERC ¶ 61,047 at ¶ 39 & n.37 (2009).

resolved under a "black-box" settlement.[961] The TAPS Owners' filed rates for 2009 and 2010 are currently under litigation at FERC.[962]

565. The Owners have tried to predict future tariffs for the next several decades in order to determine the net present value of that tariff income stream to apply in this ad valorem tax case. The Owners presented the testimony of former FERC Commissioner Suedeen Kelly in support of their position that the FERC Opinion No. 154-B methodology is straightforward and can be used to predict net cash flow over the long term and that settlement rates on TAPS would not vary significantly from what would result under Opinion No. 154-B.[963] However, Ms. Kelly did not opine as to what future tariffs this Court should apply under a tariff-based income approach. And although Ms. Kelly served as a FERC Commissioner, she had never been in a FERC hearing room on a TAPS matter.[964] Ms. Kelly is currently an attorney whose law firm represents ExxonMobil Corporation[965] and acknowledged that she was not an expert in ad valorem tax matters. At trial, in response to a question from the Court, Ms. Kelly answered that FERC could have abandonment authority over oil pipelines, but she subsequently corrected that testimony and stated that FERC had no such authority.[966]

---

[961] Tr. 8933 (Grasso). The TSA required the TAPS Owners to file yearly rates using the TSM. Tr. 7647 (Toof). The TSM ended in 2008. Tr. 7668 (Toof). The TAPS Owners have each filed for multiple rate increases in 2009 and 2010. *See* Tr. 8890-91 (Grasso). This process of filing multiple rate increases is known as "pancaking." Amended Decision ¶ 492.

[962] Tr. 7667 (Toof).

[963] Tr. 7211, 7212, 7216 (Kelly).

[964] Tr. 7287-89 (Kelly)

[965] Tr. 7258 (Kelly).

[966] Tr. 7179-80, 7298-7303 (Kelly).

566. Ms. Kelly had no knowledge of how rates established under the TSM would compare to rates established under Opinion No. 154-B.[967] Ms. Kelly did not know the specifics of the TAPS Owners' 2007-2010 rate filings at FERC and was not aware of the TAPS SR proceeding pending at FERC.[968] Based on the foregoing, this Court was not persuaded by Ms. Kelly's testimony regarding FERC rate setting, including Opinion No. 154-B methodology and its application to determine TAPS' tariffs.

567. This Court was also unpersuaded by Dr. Toof's testimony that TAPS' tariffs have been stable and predictable.[969] Dr. Toof has never sponsored an Opinion No. 154-B revenue requirement before the FERC.[970] Dr. Toof has never prepared a rate filing and does not consider himself a rate of return expert.[971] Although Dr. Toof in the TAPS' FERC rate case took the position that the TSM produced just and reasonable rates, Presiding Judge Cintron, the Commission, and the Court of Appeals for the D.C. Circuit all disagreed with Dr. Toof's position on this issue.[972]

568. This Court finds that the regulatory status of TAPS is so unique that the projection of future tariffs for it would be less reliable and less predictable than for other regulated pipelines.[973] When asked "Is there any crude oil pipeline in the United States that

[967] Tr. 7295-96 (Kelly).

[968] Tr. 7296-98 (Kelly).

[969] Tr. 7681 (Toof).

[970] Tr. 7704 (Toof).

[971] Tr. 7705-06 (Toof).

[972] Tr. 7706 (Toof).

[973] Tr. 8539-8540 (Sullivan).

is in the unique regulatory status of TAPS [and the pipelines that feed into TAPS] before the FERC?" Dr. Toof responded, "They are carved out as an entity unto themselves."[974]

569. Mr. Grasso demonstrated the instability of the TAPS tariff by noting that the Owners recently filed testimony with FERC in support of their own filed rates that supported different rates than they had originally filed. Mr. Grasso explained:

> To further - what I would say to undermine the stability of the 154-B, in 2009 the Owners filed tariff rates at the FERC between $4.01 and $4.10. That case, as you know, is now subject to a proceeding called the SR proceeding, strategic reconfiguration, of which a 154-B cost-of-service is one component.
>
> Two years after the fact of 2009, testimony's [sic] filed in January of 2011 by the Owners to support their rates. Well, in January 2011, the rate that's supported for 2009 is $3.88. So two years after the fact, when rates were filed and collected at the $4.10 range, they're supporting $3.88.
>
> So, historically, it's tough to hit the mark using 154-B.[975]

570. This Court critiqued the TAPS Owners in the 2006 tax year proceeding for failing to advance a rate expert to support the Owners' tariff income assumptions.[976] In this case, the Owners again did not advance an expert who could support their specific tariff income assumptions. Regulatory Economics Group, LLC. ("REG") performed the cost-of-service calculations for American Appraisal,[977] which American Appraisal used to value TAPS based on the tariff income approach. But no witness from REG testified at trial. The Owners' rate experts at trial, Ms. Kelly and Dr. Toof, did not review or support REG's rate model or the rate calculations produced under that model.

---

[974] Tr. 7715 (Toof).

[975] Tr. 8891-92 (Grasso).

[976] Amended Decision ¶ 488.

[977] TO-7-0004.0102.

571. The REG rate calculations that American Appraisal used are not reliable. An example is the rate calculations for 2009. As discussed earlier, the TAPS Owners' FERC rate filings for 2009 ranged from $4.01 to $4.10 per barrel, and the rate advocated by the expert for the Owners in the 2009 FERC rate case is $3.88 per barrel. But in this ad valorem tax case, the Owners are proposing far lower rates of $3.07, $3.40, $3.03, and $3.25 per barrel on January 1, 2009.[978] The lower the projected tariff, the lower the net present value of the income stream.

572. Regulatory rate models are not intended to be used to predict future cash flows. Consistent with that reality, Dr. Toof declined to predict the outcome of the current TAPS' rate proceedings before FERC and the RCA.[979]

573. In sum, the evidence at trial persuasively demonstrated that TAPS' tariffs do not provide a stable or predictable foundation upon which to base the economic value of TAPS.[980]

574. SARB has repeatedly found that tariff income alone does not capture the economic value of the pipeline. As SARB explained in its 2007 Decision:

> The value of a pipeline's tariff income stream is generally only a portion of the value of the pipeline. That portion is the value of the original investment, plus capital expenditures and a reasonable return on these outlays of capital, which make up the tariff rate base. The tariff regulatory process attempts to ensure that shippers pay the pipeline owners only once for the capital costs through their tariff payments. . . . The tariff is based on depreciated capital costs, not current market value as a stand-alone property or the pipeline's current value as part of an economic unit. A regulated tariff does not

[978] TO-07-0004.0195; TO-07-0004.0208; TO-07-0004.0219; TO-07-0004.0232.

[979] Tr. 7740-41 (Dr. Toof acknowledged that at his deposition he had declined to predict the outcome of the strategic reconfiguration case pending at FERC and the RCA, since he "was not in the prediction business.").

[980] Tr. 8884-91 (Grasso).

produce an income that would capture the current economic value of the pipeline.[981]

575. For all the foregoing reasons, and consistent with the determinations made by many other courts, this Court finds that the Owners have failed to demonstrate that the Division and SARB's use of the RCNLD approach and its rejection of a tariff income approach was unreasonable and unsupported by the record. Instead, the record clearly demonstrates that the use of the RCNLD methodology to value TAPS for ad valorem tax purposes is a fundamentally sound valuation determination.

IX. THE COMPARABLE SALES APPROACH

576. The third primary approach to valuation is the comparable sales approach. "In the sales comparison approach, the appraiser develops an opinion of value by analyzing closed sales, listings, or pending sales of properties that are similar to the subject property."[982]

577. The sales comparison approach is most reliable when there is an active market providing a sufficient number of sales of comparable property that can be independently verified through reliable sources.[983] The "important concepts are 'active market' and 'verifiable information.'"[984] The sales comparison approach "is not feasible when the subject property is unique" or "if an active market for that property does not exist."[985]

---

[981] MUN7-0234 at 16. *See also* MUN7-0235 at 15, 17; MUN7-0236 at 30.

[982] *The Appraisal of Real Estate* at 297.

[983] *Valuing Machinery and Equipment* at 122.

[984] *Valuing Machinery and Equipment* at 122.

[985] *Valuing Machinery and Equipment* at 122.

578. It is uncontested that TAPS is a unique, limited-market and special purpose property.[986]

579. As explained by the Minnesota Supreme Court:

> Because the [property] is specially adapted to a unique use and will not readily be sold to another user, the very nature of special purpose property is such that market value cannot readily be determined by the existence of an actual market, and therefore other methods of valuation, such as reproduction cost, must be resorted to . . . . Usually . . . comparable sales are not available for a [property] that is special use property. Nor is the income approach always directly relevant. Thus, where the owner is less interested in the income the property will generate than in occupying a [property] uniquely suited for the owner's special type of business, the reproduction cost minus depreciation method has been held to be appropriate for determining the market value of a [property], rather than an income approach.

Fed. Reserve Bank of Minneapolis v. State, 313 N.W.2d 619, 622 - 624 (Minn. 1981) (quotations omitted).

580. *The Appraisal of Real Estate* specifies that a proper "market analysis and highest and best use analysis are fundamental to the sales comparison approach."[987]

581. The record demonstrates that sellers of an interest in TAPS sell when they no longer have an integrated use for TAPS. Similarly, the record demonstrates that buyers of an interest in TAPS buy only when they have an integrated use for TAPS.[988] In short, the purchase and sale of interests in TAPS have been driven by each oil producing company's integrated economics rather than by tariff income.[989]

---

[986] Tr. 11903 (Remsha); Loke Dep. 60 (June 1, 2011).

[987] *The Appraisal of Real Estate* at 299-300.

[988] Tr. 12682 (Goodwin).

[989] Tr. 12682 (Goodwin).

582. Mr. Sullivan, on behalf of the Municipalities, persuasively discussed the fundamental differences between the transfer of pipeline interests in Alaska and the pipeline markets in the Lower 48.[990] He noted that there is only one independent shipper on TAPS after 34 years of operation.[991] He compared the market dynamics of the ANS and TAPS with two major oil producing basins in the Lower 48, the North Dakota basin and the Gulf Coast basin. He explained that in those Lower 48 markets, the pipelines are not owned or dominated by affiliates of the oil producers. Instead there are hundreds of independent producers, shippers, and marketers in each of those basins.[992] The Court was persuaded that comparing sales from different markets with fundamentally different market drivers than those existing in Alaska or for TAPS is not helpful in framing the economic value of TAPS.

583. Other courts have recognized that the absence of comparable sales and a meaningful income stream typically result in the use of the cost approach for limited-use and special-purpose property.[993]

\\

\\

\\

\\

\\

\\

---

[990] Tr. 8550-64 (Sullivan). *See also* Tr. 12311-12 (Podwalny); Tr. 12682 (Goodwin).

[991] Tr. 8539-40, 8562-64 (Sullivan).

[992] Tr. 8562-65 (Sullivan).

[993] *See, e.g., Brooklyn Union Gas Co. v. State Bd. of Equalization*, 482 N.E.2d 77, 83 (N.Y. 1985); *Guild Wineries & Distilleries v. County of Fresno*, 51 Cal. App. 3d 182, 187-88 (Ca. Ct. App. 1975); *First Wis. Bankshares Corp. v. United States*, 369 F. Supp. 1034, 1039 (E.D. Wis. 1973).

584. As with the tariff income approach, the sales comparison approach has been repeatedly considered but determined not to be a reliable approach for determining the economic value of TAPS by both the Division and SARB. Thus, in 2007, SARB held that "there was no comparable property or representative sales of partial interests to make a reliable comparable sales valuation of the TAPS."[994] And in 2009 SARB found as follows:

> The 2009 comparable sales value estimates could not be relied on due to the same problems that these valuations have suffered from since they were first considered in the 2001 TAPS assessment. There are no other pipeline properties that are similar enough to the TAPS to obtain an accurate assessed value from sales. The historical partial sales of the TAPS were not arms-length transactions and were not independent of other transactions between the buyer and seller. Grossing up small partial sales creates distortions in the values obtained.[995]

At trial, the Assessor agreed that the sales comparison approach should not be relied on by this Court due to a lack of comparables, and the partial interest sales of TAPS were old and uninformative.[996]

585. At trial, the Owners' appraiser Michael Remsha sponsored a sales comparison approach on behalf of the Owners for the years at issue.[997] But Gary Loke and not Mr. Remsha was the appraiser for American Appraisal that did the work and drafted the relevant parts of the appraisal associated with the sales comparison approach.[998] Mr. Loke was not offered by the Owners as a witness at trial. Mr. Remsha indicated he personally did not

---

[994] MUN7-0234 at 17 (2007 SARB).

[995] MUN7-0236 at 30 (2009 SARB).

[996] Tr. 12982-84 (Greeley).

[997] Tr. 11845-51 (Remsha).

[998] Tr. 11895-96 (Remsha).

investigate or verify the sales that were used in the sales comparison approach.[999] Mr. Remsha indicated Mr. Loke would have been the best person to answer questions about American Appraisal's sales comparison approach.[1000]

586. For a sales comparison approach to be helpful, the sales need to be compared with the subject and "[i]f the comparable sale is not identical to the subject, the selling price of the comparable *must* be adjusted to indicate what the selling price of the comparable would have been if the comparable had been identical to the subject."[1001] There are several elements of comparability that must be considered when adjusting the selling price of the comparable back to the subject including age, condition, capacity, features, location, motivation of the parties, price, quality, time of sale, and type of sale.[1002]

587. Mr. Loke looked at fourteen Lower 48 pipeline sales, and used an earnings multiples analysis to project value to TAPS based on these sales. He did not make any other adjustments so as to compare these properties to TAPS.

588. With regard to these fourteen transactions, American Appraisal did not speak with the seller or buyer, or otherwise independently verify or confirm the transaction details.[1003] This failure to verify was the case even where BP was a party to the transaction.[1004] Mr. Loke did not know whether any of the fourteen sales transactions were due to merger and acquisition regulatory requirements.[1005] Mr. Loke was apparently

---

[999] Tr. 11896 (Remsha).

[1000] Tr. 11895-97 (Remsha).

[1001] *Valuing Machinery and Equipment* at 124 (emphasis added).

[1002] *Valuing Machinery and Equipment* at 126-128.

[1003] Loke Dep. 74-75, 86-87, 104-05 (June 1, 2011).

[1004] Loke Dep. 86-87 (June 1, 2011).

[1005] Loke Dep. 95-96 (June 1, 2011).

unaware that Transaction No. 14 was between related parties until he learned of that detail from comments made by Mr. Connolly at his deposition.[1006]

589. Of the fourteen sales transactions considered, only four were deemed by Mr. Loke to be relevant as an indicator of value for TAPS.[1007] The sales prices of the four selected transactions ranged from a high of $2.4 billion to a low of $158 million.[1008] Mr. Loke did not consider any of the four selected sales to be limited market properties and, as noted above, made no adjustments to those sales in an effort to reflect comparability with TAPS.[1009]

590. Mr. Loke testified that he had a "very challenging time" finding public domain information with regard to transfers of fractional TAPS' interests.[1010] He relied on information that he received from counsel for the Owners, but acknowledged that obtaining information in this manner was not a standard or common practice.[1011]

591. One of the Owners' other appraisal experts, Thomas Tegarden, testified at trial that he "would agree there is a lack of comparable sales."[1012]

592. The weight of the evidence presented at the trial de novo demonstrates that there are no comparable sales that inform the economic value of TAPS.

[1006] Loke Dep. 69-70 (June 1, 2011).

[1007] Loke Dep. 98 (June 1, 2011).

[1008] TO-07-0004 at 89 (American Appraisal); Loke Dep. 67-68 (June 1, 2011).

[1009] Loke Dep. 101 (June 1, 2011).

[1010] Loke Dep. 103-107 (June 1, 2011).

[1011] Loke Dep. 103-107 (June 1, 2011).

[1012] Tr. 10313 (Tegarden).

X. RECONCILIATION AND CONCLUSION

593. USPAP does not require reliance upon any particular method of appraisal. Instead, it provides as follows:

> In developing a real property appraisal, an appraiser must reconcile the quality and quantity of data available and analyzed within the approaches used, and reconcile the applicability or suitability of the approaches used to arrive at the conclusion(s).[1013]

594. The record before this Court reflects that the Division and SARB carefully considered each of the three major approaches to value, as well as the fact that TAPS is a regulated pipeline. No party has demonstrated that reliance on the cost approach was improper, or unsupported by the record, or constituted a "clear adoption of a fundamentally wrong principle of valuation."[1014]

595. This Court has also carefully considered each of the three approaches to value – the cost approach, the income approach, and the sales approach. Based upon all of the evidence presented to this Court over the course of the nine-week trial de novo concerning the assessed value of TAPS from 2007 to 2009, this Court will rely solely on the cost approach for the 2007, 2008, and 2009 assessments.

596. For the reasons discussed in Section VII of this decision, this Court relies on the Pro Plus cost study for the valuation for TAPS, as adjusted herein.

597. This Court has been presented with considerably more evidence than was before either the Division or SARB, including extensive cross-examination of all of the experts and other witnesses, and has concluded that in certain respects, SARB's 2007, 2008, and 2009 valuation of TAPS resulted in an improper valuation of TAPS, particularly

[1013] USPAP Standard 1- 6.

[1014] *See N. Star Alaska Hous. v. Bd. of Equal.*, 778 P.2d 1140, 1144 n.7 (Alaska 1989).

with regard to the amount of the RCN, the amount of the scaling adjustment, and the lower limit of TAPS' capacity. Also, evidence at trial persuasively demonstrated that the life of TAPS based on its proven reserves and incorporating its minimum capacity throughput limitations as of the lien dates for 2007, 2008, and 2009 is at least until 2065.

598. Based on the foregoing, the following is a summary of this Court's determination of the assessed value for TAPS as of January 1, 2007, 2008 and 2009,[1015] set forth in millions of dollars:

Jan.1, 2007	Jan. 1, 2008	Jan. 1, 2009	
$17,645	**$19,324**	**$19,137**	**Replacement Cost New (RCN)**
($194)	*($194)*	*($194)*	*Less Land & ROW*
($243)	*($228)*	*($250)*	*Less Additional Functional Obsolescence*
$17,208	**$18,902**	**$18,693**	**RCN Less Land & ROW & Additional FO**
($5,605) *32.57%*	*($6,300)* *33.33%*	*($6,300)* *33.70%*	*Less Economic Age-Life Depreciation*
$11,603	**$12,602**	**$12,393**	**RCN Less Economic Age-Life Depreciation**
($2,691)	*($2,968)*	*($3,134)*	*Less Scaling of Pipe and VMT*
($165)	*($184)*	*($204)*	*Less Scaling of Pumps*
$8,747	**$9,450**	**$9,055**	**RCN Less All Depreciation**
$194	*$194*	*$194*	*Plus Land & ROW*
$8,941	**$9,644**	**$9,249**	**TOTAL RCNLD (in millions)**

[1015] The Court's Amended Decision ¶ 509, as well as SARB's decisions in 2007 and 2008, *see, e.g.*, MUN7-0236 at 13, 15, had deductions for certain non-taxable assets and the Valdez Terminal Office building. Because those assets were not included in the Pro Plus Study, the adjustments are no longer necessary.

The primary reasons for the variations from year to year are due to market changes in the estimates made by Pro Plus in its RCN for the cost of steel and labor rates as of each of the lien dates.

599. This matter concerns the assessed valuation of TAPS as of January 1, 2007, 2008, and 2009. It is before the Superior Court pursuant to a specific statute that accords to taxpayers and affected municipalities the right to a trial de novo before the Superior Court of an administrative determination of the value of pipeline property.[1016] Pursuant to that statute, this Court conducted a non-jury trial lasting approximately nine weeks in the fall of 2011. For the reasons expressed herein, this Court finds that as of January 1, 2007, 2008, and 2009, the "full and true value" of the Trans Alaska Pipeline System, "with due regard to the economic value of the property based on the estimated life of the proven reserves of gas or unrefined oil then technically, economically, and legally deliverable into the transportation facility"[1017] is \$8.941 billion for 2007, \$9.644 billion for 2008, and \$9.249 billion for 2009.

ENTERED at Anchorage, Alaska this 30th day of December 2011.

Sharon Gleason

SHARON L. GLEASON
Superior Court Judge

I certify that on 12.30.11
a copy was mailed to each of the following
at their address of record:

Anne Misner
Judicial Assistant / ~~Deputy Clerk~~

Seedorf, Mahoney, Palumbo, Garatoni, Gabel, Diemer, Johnson, Long, Richards, Brena, & Broker

[1016] AS 43.56.130(i).

[1017] AS 43.56.060(e)(2).